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Folder Title:
Climate Change Other Natural Gas

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Arctic Resources Company, Ltd.
3 Riverway, Suite 1375
Houston, Texas 77056
Phone: (713) 888-0133
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Facsimile Transmittal Sheet

DATE: Friday, September 29, 2000

TO: Mr. Roger Ballantine
Deputy Asst. to the President
Environmental Initiatives

FAX: 202.456.1736

FROM: Bob Murphy, President
Arctic Resources Company, Ltd.

PHONE: 713-888-3300
FAX: 713-888-0239

RE: Arctic Gas

No. of Pages: 7

Message:

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Robert D. Murphy, Jr.
President

September 28, 2000

Mr. Roger Ballantine
Deputy Assistant to the President
Environmental Initiatives
Old Executive Office Building, Room 115
Washington, D. C. 20500

Dear Mr. Ballantine:

The stranded natural gas reserves of Alaska and the Canadian Arctic become more important to the U. S. gas supply strategy with each passing day. The important decisions that will be made concerning the transportation alternatives for these reserves must be based on the relevant facts—all of the facts. Otherwise, the U. S. risks critical supply delays.

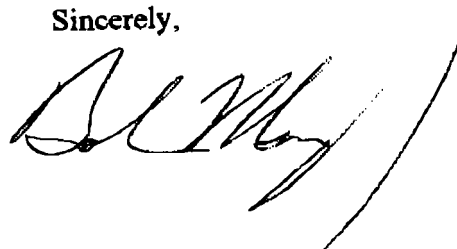
In the course of analyzing pipeline alternatives there has been a great deal of discussion in Alaska concerning pipeline economics and gas supplies to Alaskan communities. These are important issues. There has been, however, relatively little discussion of the importance of Canada, and in particular, the Northwest Territories, in the process. The degree to which they and their issues are not integrated into the pipeline route selection process can be detrimental to U. S. gas supplies. The reason that I have written this letter is that I believe more active government attention is needed to encourage what is best for the U. S., Canada, and Alaska based on the realities of the year 2000, rather than the outdated restrictions of 1977.

I have attached a copy of a letter that I sent to Governor Knowles of Alaska related to this subject. As you will see, Alaska's natural gas potential is great. However, this potential, along with that of the U. S., will not be fully achieved without addressing

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the issues of Canada and of the Northwest Territories. Addressing these issues with the facts of the year 2000 will do the most to encourage long-term, dependable gas supplies for the U. S.

Sincerely,

A handwritten signature in black ink, appearing to read "D. L. King", followed by a long, sweeping horizontal stroke.

attachment



Robert D. Murphy, Jr.
President

September 27, 2000

The Honorable Tony Knowles
Governor, State of Alaska
Court Plaza—Third Floor
240 Main Street
Juneau, AK 99801

Dear Governor Knowles:

I am writing to address two issues that I know are very important to you and other Alaskan leaders. The first issue relates to the impact of ARC's planned pipeline on gas supplies to Alaskan communities. The second issue relates to fundamental conditions, including important Canadian conditions, which we believe must be satisfied in conjunction with your framework, in order for a modern era pipeline to successfully commercialize Alaska's valuable gas resources.

Having met with you and other Alaskan political leaders, ARC recognizes the importance of the energy needs of Alaskan communities. These needs must be a part of any gas commercialization solution. When one looks at all of the conditions for a pipeline to actually be built, our approach may represent the best gas supply opportunity for the citizens of Alaska. The ARC approach also represents the best opportunity for the State to maximize the value of Alaska's gas reserves for years to come, while providing significant Alaskan business and employment opportunities during and after construction.

The rationale for these positions stems from the fundamental conditions which any pipeline must be able to meet in concert with your framework.

- First, if a pipeline is to be built, it must be economically viable in the eyes of the producers and the financial markets. This viability must be demonstrated not just at today's record high gas prices, but also at more moderate price levels which industry and government experts expect to return by the time an Alaskan pipeline could be operational. This viability will also provide added long-term protection for Alaskans by better ensuring continued operation and natural gas development during low gas price cycles.

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- Second, the pipeline must provide a significant economic benefit to Canada and its key stakeholders. Canadian cooperation, at all levels, is vital to final approval of any pipeline transporting Alaskan gas through Canada to the Lower 48. Despite significant efforts over the past two decades, many regulatory and permitting hurdles remain for each of the Alaskan pipeline alternatives. It is reasonable to expect Canadian stakeholders and authorities to seek solutions that will protect their interests. They will take into account the impact that a pipeline transporting Alaskan gas through Canada will have on Canada and its Aboriginal interests, some of which have Constitutional protection. They will consider the substantial delay that a southern route could have on necessary and full development of the sizable reserves in the Canadian Arctic, and in particular in the Mackenzie Delta. They will also consider the diminished economic potential of Mackenzie Delta reserves should a southern route effectively preclude a cost effective linkage of the Alaskan and Canadian Arctic reserves. Incidentally, the linkage of these reserves will materially increase State of Alaska revenues by increasing wellhead netbacks and encouraging additional Alaskan gas exploration and development. This linkage can also greatly increase the security of U.S. natural gas supplies by connecting a larger gas reserve pool directly to U.S. markets.

The realities of the year 2000 are very different from the limitations of 1976. A number of observers have noted that they are not certain that the route decisions made twenty-five years ago would be made today because of major changes that have occurred in pipeline technology, deregulation, and Aboriginal political and socio-economic issues. Just last week, Northwest Territories Premier Stephen Kakfwi, in a speech at a Canadian energy conference, made clear his view that "a Mackenzie Delta route is the option that is in the best interest of all Canadians". This was not his view in 1976.

While Aboriginal leaders in the Northwest Territories are now firmly in support of a Mackenzie Valley pipeline, the same is not true about Yukon Aboriginal leaders regarding the southern route. The southern route would traverse lands that fall within the traditional land claim area of the Kaska First Nation. The chief land claims negotiator for the Kaska, Dave Porter, stated in a presentation last week that there would be no pipeline without settlement of land claims. While not opposed to a pipeline, he also stated, "That (pipeline) is not a priority for us. Our priority is to get a just and fair settlement for our people." At the same conference, Mr. Hammond Dick, Tribal Chief of the Kaska, stated, "We insist on a major say in what happens in our traditional territories." Mr. Dick also stated that "large scale resource projects are not new to the Kaska, to this day, we live with the harmful effects of the Alaska Highway project". In 1976, similar statements by Mackenzie Valley Aboriginal leaders contributed to the imposition of a ten-year moratorium on pipeline development.

Alaska has a number of important issues to evaluate as it analyzes gas pipeline alternatives. In the course of its analysis, Alaska (and also Ottawa and Washington) will need to consider the concerns of Yukon Aboriginal leaders. Decision makers will also need to address the views of Premier Kakfwi and other affected Canadian groups who should seek to encourage logical, pragmatic solutions that can protect their interests with ARC's northern route while simultaneously maximizing the natural gas benefits for Alaska, Canada and the U.S.

- Third, any gas pipeline must be environmentally sound and sensitive to subsistence issues. Gas pipeline technology, coupled with extensive data collections by government agencies in the U.S. and Canada, have improved materially in the past twenty-five years enabling the type of high pressure trenched pipeline envisioned by the ARC approach. Approximately three hundred and fifty miles of the pipeline will be buried four miles offshore in thirty to sixty feet of water. The bottom of the pipe will be fifteen feet below seabed with an eleven foot native cover to provide ample protection from the one to two foot ice scours that occur in that water depth. Interestingly, a substantial percentage of the natural gas supplies to North America and Europe are already safely transported through offshore pipelines, which in some cases lie thousands of feet below the ocean surface.

ARC has initiated environmental and coordination discussions with U.S. and Canadian regulators concerning the planned route, construction methodologies and environmental precautions. These discussions have been aided by volumes of relevant data that has been collected by government agencies over the past thirty years concerning major portions of the ARC route. ARC's work is not complete. Neither is the work of other alternatives. Nonetheless, officials have led us to believe, after regulators truly understand the approach, that we should not encounter insurmountable obstacles.

The construction of the offshore portion of the pipeline can be managed without interfering with whale migratory patterns. The route does not cross any mountain ranges. The ARC route leaves untouched some of the most pristine ranges in North America and their wildlife habitats. Finally, the route is outside of ANWR and other Alaskan and Canadian parks or caribou grounds.

I believe that the ARC approach will satisfy all of the above conditions, as well as your important principles.

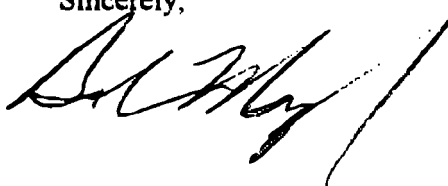
I note with interest the quotation from K. Terry Koonce, President of ExxonMobil Production Company, in his recent testimony to the Senate Energy and Natural Resources Committee. He stated "there is sufficient gas on the North Slope of Alaska for multiple

projects". We wholeheartedly agree. However, we believe Alaska's challenge, in conjunction with solving the Canadian issues, will be to ensure that there is an attractive economic transportation foundation that will encourage producers to explore for and develop the remaining two-thirds of Alaska's natural gas potential. Overly expensive transportation costs for the first major project will impact the timing of and degree to which additional Alaskan reserves and gas projects become realities.

Regarding gas for central Alaska, we believe there are several potential viable approaches that can be accomplished in concert with a Canadian-friendly project. Importantly, these alternatives can be pursued without mortgaging the State of Alaska's long-term prospects for gas development. There are a number of experts on these alternatives both within Alaskan producer organizations as well as within State government. As an interim measure, however, we have proposed a propane solution for Fairbanks and other central Alaska communities as part of our project while State leaders address more comprehensive solutions with the added budgetary comfort of materially greater State revenues for the benefit of all Alaskans from profitable gas development.

I hope that this information will be helpful to the understanding of some important issues outside of Alaska that, once incorporated, will keep Alaskan gas commercialization on the fast track proposed by you.

Sincerely,



c: Lt. Governor Fran Ulmer
Commissioner Wilson L. Condon—Department of Revenue
Commissioner Michele D. Brown—Department of Environmental Conservation
Commissioner Pat Pourchot—Department of Natural Resources
Mr. Mike Abbott—Economic Development, Office of the Governor
Mr. Roger Marks—Petroleum Economist, Department of Revenue

Hydraulic Fracturing

- **LEAF v EPA Decision and Resulting Unnecessary Regulatory Changes Will Cause Gas Supply Problems**
- **EPA Study Should be Science-Based and Non-Duplicative**

- The Ground Water Protection Council (or GWPC, made up of state agencies) in 1998 surveyed 10,000 hydraulically fractured wells in thirteen states, and found no instances of contamination of drinking water. The GWPC, states and the Interstate Oil and Gas Compact Commission have all taken the position that there is no reason to impose Safe Drinking Water Act regulation to replace state regulation that has been in place for decades.
- The GWPC is engaged in a peer-review follow-on study, with full EPA participation, to verify its 1998 findings of no environmental harm from hydraulic fracturing.
- In the meantime, as a result of the 11th Circuit Court of Appeals' 1997 decision in LEAF (Legal Environmental Assistance Foundation) v. EPA on whether hydraulic fracturing falls under the legal definition of "underground injection", and despite a long record of successful regulation of hydraulic fracturing under state requirements, Alabama was forced to begin regulating hydraulic fracturing under the Safe Drinking Water Act. A principal requirement is that SDWA-quality fresh water be used for fracturing.
- LEAF is challenging the more stringent state rules, apparently seeking national EPA regulation, including perhaps separate hearings on all proposed hydraulic fractures, thousands of which are routinely carried out each year in the completion of gas and oil wells.
- Rocky Mountain environmental groups have met with LEAF's lawyer, and it is quite likely that a similar case will be considered for filing in the West, forcing EPA to again defend against unnecessary federal regulation.
- At the very time natural gas demand is expected to rise by one-third or more over the next decade (according to the National Petroleum Council's 1999 gas study), increased unnecessary regulation of hydraulic fracturing -- a completion technique that will be required on 60-80% of all future gas wells -- could increase the cost of a well by as much as \$50,000, making many wells uneconomic.

There should be:

- bipartisan engagement to craft a legislative clarification that hydraulic fracturing is not "underground injection" (or disposal) of wastes as contemplated under the SDWA;
- engagement by EPA to help draft and see approval of such a clarification that allows states to address real problems if they are found; and,
- increased EPA dialogue with the states on how the GWPC science-based study regarding hydraulic fracturing can accomplish agency needs rather than initiation of a new EPA study, the design of which has raised very significant methodology concerns.

DOMESTIC PETROLEUM COUNCIL

William F. Whitsitt
President

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202/544-7100 • Fax 202/543-0616 • Email wfwhitsitt@aol.com

Comments by

Dr. William F. Whitsitt
President
Domestic Petroleum Council

for the
Domestic Petroleum Council
and the
International Association of Drilling Contractors

on the
EPA Hydraulic Fracturing Study

August 24, 2000
Washington, DC

There is no evidence that the hydraulic fracturing at issue has resulted in any contamination or endangerment of underground sources of drinking water.

--EPA Administrator Carol Browner

In May of 1995, in denying the Legal Environmental Assistance Foundation's petition to withdraw approval of Alabama's Underground Injection Control program in connection with alleged contamination caused by hydraulic fracturing of a coalbed to produce natural gas, EPA Administrator Carol Browner said*

There is no evidence that the hydraulic fracturing at issue has resulted in any contamination or endangerment of underground sources of drinking water.

She also pointed out that

Hydraulic fracturing is closely regulated by the Alabama Oil and Gas Board...

Those two statements are as pertinent today as they were when they were written, and they provide an important part of the context for today's meeting:

- hydraulic fracturing has been safely carried out for many decades as a crucial process in providing the premium natural gas fuel that helps power the new economy, and,
- states regulate this and other natural gas exploration and production processes with a sharp focus on their respective geographic, geologic and hydrologic conditions--and they do it well.

* Letter to David A. Ludder, Esq., General Counsel, Legal Environmental Assistance Foundation, Inc., May 1995.

As a further context element, we need to remember, as the EPA Study Design document states, that the Groundwater Protection Council (GWPC), made up of state agencies, completed a 13-state, 10,000-well study of hydraulic fracturing in 1998. It found no evidence of environmental harm.

Even the court in the *LEAF* case cited in the EPA study announcement made no determination of environmental harm. Its decision was based on a technical legal definition.

And, as the Department of Energy has reminded us in its recent *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology* report, hydraulic fracturing had already been used nearly a million times by 1988 and continues at a rate of some 25,000 each year.

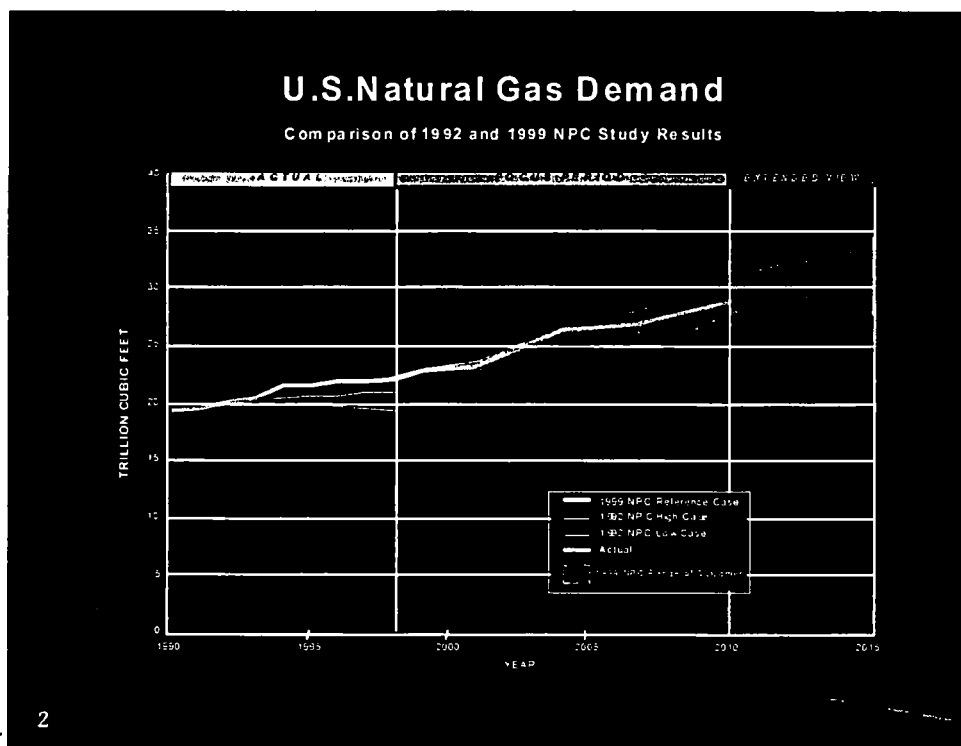
EPA Hydraulic Fracturing Study

**Comments of the
Domestic Petroleum Council
International Association of Drilling Contractors**

Dr. William F. Whitsitt
President
Domestic Petroleum Council

Today I want to provide further context for the EPA study--drawing from the work done by the National Petroleum Council report on the challenges we face in meeting the dramatic increase projected in future natural gas demand. I will also raise several key questions that need to be considered before the study goes forward.

I do so on behalf of the large independent exploration and production company members of the Domestic Petroleum Council that drill 60 percent of all independent wells in the United States and produce some 20 percent of the nation's natural gas. I also do so on behalf of the International Association of Drilling Contractors that represents the entire worldwide drilling industry.

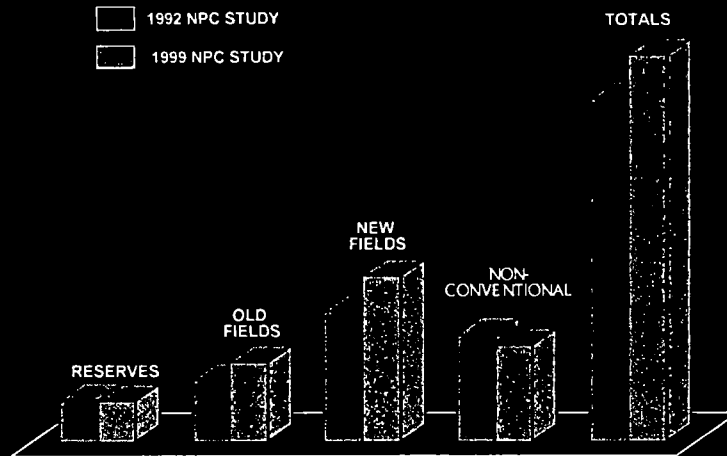


First, the NPC natural gas study* projects that

- Natural gas demand is estimated to grow by perhaps 30% or more over the next decade because of this clean, premium fuel's benefits in heating our homes, cooling our offices, providing the many products for which it is a feedstock and, as I mentioned, powering the computerized economy of today and the future.
- The largest growth sector for gas will be electricity generation, accounting for approximately half of the demand growth.
- Of estimated new electricity generation capacity, more than 90% will be gas-fired.

* *Meeting the Challenges of the Nation's Growing Natural Gas Demand* (December 1999)

U.S. Natural Gas Resource Base Estimates



- The natural gas resource base is adequate. But significant challenges will have to be met in converting that resource base to supply, and in delivering that supply to consumers.

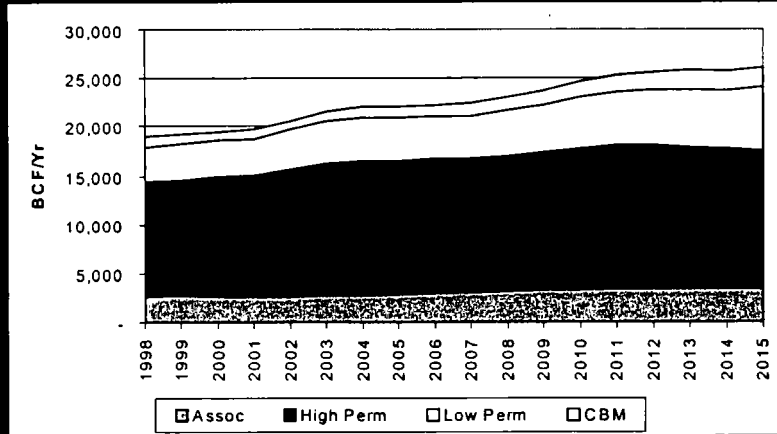
New Supply Will Come From

- ***Deeper Wells***
- ***More Non-Conventional Sources***
- ***Deeper Water***

5

Since most of our new supplies will come from deeper wells, more non-conventional sources like tight sands, Devonian Shales and coal seams, one of the most significant areas of challenge is that of technology--not just its advancement, but also its continued application. Hydraulic fracturing is a perfect example.

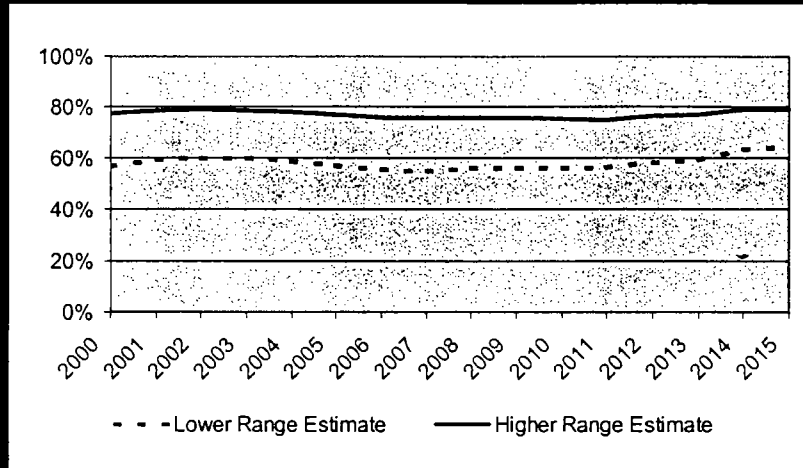
Lower 48 Gas Production (By Type)



NPC Reference Case

This technology is crucial to bringing consumers the increasing share of our natural gas supply in the future that will come from the non-conventional formations I mentioned. In fact, it is estimated that those sources will contribute one third of our supply by 2015, compared with approximately one quarter today. Most of those formations will need to be hydraulically fractured.

Percentage of Hydraulically Fractured Gas Wells



Put another way, according to work done by members of the National Petroleum Council Supply Task Group, something in the range of 60-80% of our gas wells in the future will need to be hydraulically fractured.

The good news is that our industry and the service companies that actually do the hydraulic fractures for us are meeting this challenge. They and we are proving with hundreds and thousands of operations daily that we can use our advanced technology safely to meet the nation's energy needs.

This brings me to the questions about the planned EPA study and its design. They should be answered before it proceeds.

EPA Study Questions

Goal?

Science?

First, what is the study's specific goal?

It is referred-to in various ways in EPA documents. For example, it is a "Coalbed Methane (CBM) Study". Then it is a study of "...the environmental risks associated with hydraulic fracturing...." The study design document also mentions "...reports from citizens..." regarding "...ground water loss...." These and other descriptions of the study point to the likelihood of an extremely wide, lengthy, costly and complex inquiry into exploration and production process and technological detail, and state constitutional, legal and regulatory responsibilities that may or may not be related to hydraulic fracturing specifically.

Based on communication with the Environmental Protection Agency over more than a year, we have understood that the principal goal of any inquiry would be to verify the GWPC study's findings. A much simpler survey could accomplish that goal.

Second, even if the goal of the study is specified, what are the survey and other scientific protocols that will be used in gathering and analyzing information? Others today will address sound science-related concerns more specifically.

We encourage a refinement of the study design to meet our concerns.

We remain ready to help the study managers, contractors and others better understand the hydraulic fracturing process, its role in providing natural gas for the nation, and how we conduct our business to protect and enhance the environment.

AMERICAN GAS ASSOCIATION

From: Charles H. Fritts
Vice President, Government Relations
400 North Capitol Street, NW
Washington, D.C. 20001

Phone: (202) 824-7220
Fax: (202) 824-7090
E-Mail: cfritts@aga.org

9/7/00

Roger Ballentine White House Climate Office 202 456 – 1736

Roger,

Per our conversation, here is a list of federal courthouse projects. We have spoken with GSA about BCHP and gas/electric hybrid systems in several.

Bob Peck and David Eakin (202-501-1726) are our contacts at GSA.

A demo at a few of these facilities would be great.

4 pages

TO Janet
what can we do?

03/14/00

Five-Year Courthouse Project Plan 2001-2005

As Approved By the Judicial Conference of the United States

In Numerical Order

(dollars in millions)

FY 2001			Score	
1	Los Angeles, CA	S&D	\$36.2	85.0
2	Seattle, WA	Const	\$179.4	85.0
3	Richmond, VA	S&D	\$19.6	85.0
4	Gulfport, MS	Const	\$44.8	76.6
5	Washington, DC	Const	\$109.5	75.4
6	Eugene, OR	Const	\$63.3	73.7
7	Buffalo, NY	S&D	\$3.6	68.3
8	Springfield, MA	Const	\$41.4	67.3
9	Miami, FL	Const	\$121.9	62.0
10	El Paso, TX	S&D	\$7.2	61.9
11	Mobile, AL	S&D	\$8.1	61.3
12	Fresno, CA	Const	\$111.0	60.1
13	Norfolk, VA	S&D	\$9.6	58.9
14	Las Cruces, NM	S&D	\$1.9	56.3
15	Salt Lake City, UT	Const	\$68.2	55.9
16	Little Rock, AR	D	\$5.4	54.8
17	Rockford, IL	S&D	\$2.8	54.3
18	Cedar Rapids, IA	S&D	\$13.6	52.9
19	Nashville, TN	S&D	\$13.8	51.8
20	Erie, PA	Const	\$27.0	47.3
21	Savannah, GA	Const	\$46.5	45.8
			\$934.8	

FY 2002			Score	
1	Richmond, VA	Const	\$54.8	85.0
2	Buffalo, NY	Const	\$42.6	68.3
3	Pt. Pierce FL	S&D	\$1.9	65.7
4	Jackson, MS	S&D	\$4.2	64.8
5	El Paso, TX	Const	\$36.6	61.9
6	Austin, TX	S&D	\$2.5	61.5
7	Mobile, AL	Const	\$70.6	61.3
8	San Diego, CA (USDC)	D	\$12.6	58.4
9	Little Rock, AR (USDC)	Const	\$57.6	54.8
10	Cape Girardeau, MO	Const	\$30.4	52.3
11	Orlando, FL	Const	\$39.9	50.3
12	San Jose, CA	D	\$10.3	39.5
			\$364.1	

Note: S = Study; D = Design; Const = Construction.

Five-Year Courthouse Project Plan 2001-2005

As Approved By the Judicial Conference of the United States

In Numerical Order

(dollars in millions)

FY 2003		Score	
1	Los Angeles, CA	Const	\$343.3 85.0
2	Fort Pierce, FL	Const	\$10.5 65.7
3	Jackson, MS	Const	\$23.6 64.8
4	Austin, TX	Const	\$14.3 61.5
5	San Antonio, TX	S&D	\$21.1 61.3
6	Norfolk, VA	Const	\$66.1 58.9
7	Anniston, AL	S&D	\$2.0 58.6
8	Harrisburg, PA	S&D	\$8.5 58.3
9	Greenville, SC	S&D	\$6.0 56.6
10	Las Cruces, NM	Const	\$23.1 56.3
11	Toledo, OH	S&D	\$6.9 54.4
12	Rockford, IL	Const	\$33.3 54.3
13	Charlotte, NC	S&D	\$7.9 54.0
14	Fort Lauderdale, FL	S&D	\$3.9 53.8
15	Greensboro, NC	S&D	\$6.7 53.7
16	Benton, IL	S&D	\$2.2 53.3
17	Cedar Rapids, IA	Const	\$46.7 52.9
18	Nashville, TN	Const	\$65.6 51.8
19	Sioux Falls, SD	S&D	\$4.9 50.0
			\$696.6

FY 2004		Score	
1	San Antonio, TX	Const	\$119.3 61.3
2	Anniston, AL	Const	\$11.1 58.6
3	San Diego, CA (USDC)	Const	\$95.7 58.4
4	Harrisburg, PA	Const	\$34.2 58.3
5	Greenville, SC	Const	\$34.0 56.6
6	Toledo, OH	Const	\$39.4 54.4
7	Charlotte, NC	Const	\$44.3 54.0
8	Fort Lauderdale, FL	Const	\$21.8 53.8
9	Greensboro, NC	Const	\$38.2 53.7
10	Sioux Falls, SD	Const	\$27.9 50.0
11	Chattanooga, TN	S&D	\$8.4 49.3
12	Panama City, FL	S&D	\$2.7 48.9
13	Birmingham, AL	S&D	\$4.5 48.2
14	Baltimore, MD	S&D	\$22.9 47.8
15	West Palm Beach, FL	S&D	\$5.1 47.5
16	Rochester, NY	S&D	\$1.1 47.5
17	San Jose, CA	Const	\$73.4 39.5
			\$584.3

Note: S = Site; D = Design; Const = Construction.

Five-Year Courthouse Project Plan 2001-2005

As Approved By the Judicial Conference of the United States

In Numerical Order

(dollars in millions)

FY 2005				Score
1	Benton, IL	Const	\$12.7	53.3
2	Chattanooga, TN	Const	\$47.7	49.3
3	Panama City, FL	Const	\$15.5	48.9
4	Birmingham, AL	Const	\$25.5	48.2
5	Baltimore, MD	Const	\$129.6	47.8
6	West Palm Beach, FL	Const	\$29.1	47.5
7	Rochester, NY	Const	\$12.5	47.5
8	Aberdeen, MS	S&D	\$2.4	47.3
9	Macon, GA	S&D	\$7.2	47.3
10	Jefferson City, MO	S&D	\$1.4	46.4
11	Huntsville, AL	S&D	\$1.0	46.1
12	Alexandria, LA	S&D	\$2.4	46.1
13	Durham, NC	S&D	\$2.2	45.3
			\$289.4	

Note: S = Site; D = Design; Const = Construction.

NGV INDUSTRY APPROPRIATIONS REQUEST FOR FY 2001

The Senate version of the Interior and Related Agencies Appropriations bill for FY 2001 (HR 4578) includes funding for the Clean Cities program at the level the Administration had requested \$10. million. This amount includes \$3.25 million for State Energy Program grants, an increase of \$0.5 million over last year's level. The Senate bill also includes an additional \$1 million to study the environmental impacts of ultra-fine particulates from natural gas engines.

The House version of the Interior Appropriations bill includes \$7.3 million for the Clean Cities program -- \$2.7 million below the Administration's request and below last year's level. of \$7.7 million. The House bill also includes an additional \$0.5 million for natural gas toxicity testing and to study the environmental impacts of natural gas engine ultra-fine particulates.

The following are additional projects the NGVC industry recommends be funded:

- 1) **Clean Cities funding.** The NGVC supports increased funding for the Clean Cities program to address the requests from Clean Cities programs from around the country *\$10.0 million (DOE request) plus \$5 million to meet demonstrated needs*
- 2) **Funding for natural gas buses in Washington DC.** The Washington Area Metropolitan Area Transit Authority appears to be moving toward including natural gas buses in its fleet. A barrier is the added costs for buses and infrastructure. *\$6.0 million*
- 3) **Advanced Combustion Engine R&D/Health Impact Program:** Expand work currently underway that is evaluating toxic emissions from gasoline and diesel engines to also gather natural gas exhaust samples on a dynamometer and perform toxicity testing on rats, and then compare the results with those of gasoline and diesel. *\$0.5 million more than the House version and \$1.0 million more than the Senate version*
- 4) **Alternative Fuels/Environmental Impacts program:** Expand work currently underway that is evaluating the levels of ultra-fine particulates produced by gasoline and diesel engines to also measure the levels of ultra- fine particulates produced by natural gas powered vehicles, and compare the results with those of gasoline and diesel. *\$0.5 million more than the House version*
- 5) **Alternative Fuel/Medium and Heavy Truck Program:** Develop two state-of-the-art natural gas medium and heavy duty truck systems. This program currently is scheduled to begin in FY 2002 for completion in 2004. This FY2001 funding request is to allow the program to begin one year earlier. *\$7.0 million*
- 6) **Lightweight Materials technology/Heavy Vehicle High Strength Weight Reduction Materials Program:** Accelerate the program to develop a prototype low-pressure CNG fueling system utilizing energy efficient monolithic carbon-based gas storage materials with fully reversible capability. *\$2.5 million*
- 7) **Hybrid Systems/Heavy Vehicle Propulsion Systems Program:** Complete component selection and system design definitions for candidate natural gas hybrid electric technologies, and improve regenerative braking system durability of in heavy vehicle designs; Conduct system integration efforts focused on development of three natural gas vehicle prototypes. *\$3.5 million (DOE request) plus \$6.5 million to accelerate the program*

All Interior

Natural Gas Industry RD&D Initiative

	FY2000 Approp.	FY2001 DOE Request	Gas Ind. Proposal	FY2001 House	FY2001 Senate
Distributed Generation					
Microturbines	\$2.50	\$7.00	\$10.00	(See Below)	(See Below)
Reciprocating Engines	\$2.00	\$3.00	\$8.00	(See Below)	(See Below)
Advanced Gas Turbine (Industrial Scale)	\$15.80	\$6.30	\$10.80	(See Below)	(See Below)
Subtotal, Distributed Gen.	\$20.30	\$16.30	\$28.80	\$14.30	\$16.80
Fuel Cells					
Buildings	\$3.60	\$5.50	\$8.70	\$3.50	\$5.50
Large Scale	\$44.60	\$42.20	\$42.20	\$42.20	\$42.20
Natural Gas Cooling – BCHP Buildings	\$11.00	\$15.50	\$17.50	\$11.00	\$14.60
Industrial Combustion					
Advanced Boiler Systems	\$1.00	\$2.00	\$4.00	\$2.00	\$2.00
Sensors	\$1.00	\$1.00	\$2.00	\$1.00	\$1.00
Natural Gas Vehicles Clean Cities *	\$7.70	\$10.00	\$15.00	\$7.30	\$10.50
Alt. Fuels: Engine R&D	\$12.10	\$12.50	\$17.00	\$13.50	\$13.00
Natural Gas Infrastructure	\$0.00	\$13.20	\$13.20	\$8.00	\$7.00
Natural Gas Exploration & Production: <u>Laser Drilling</u>	\$17.30	\$12.40	\$13.40	\$13.40	\$13.40
Subtotals for Industry Priorities	\$114.75	\$125.60	\$156.80	\$112.55	\$120.75
Other Nat. Gas R&D Funding	\$115.85	\$89.88	\$89.88	\$73.25	\$97.25
Total Nat. Gas R&D Funding	\$230.60	\$215.48	\$246.68	\$185.80	\$218.00

*Natural gas portion of these Clean Cities numbers is 50% except that increase requested by Gas Industry is 100% gas.

→ will get more \$ into markets.

Big savings

same to WV

all competitive funds; no earmarks

supply argument

much goes to Morgantown, WV

**Residential PEM Fuel Cell
Development of a Combined Heat and Power Unit
Department of Energy**

DESCRIPTION OF TECHNOLOGY

Residential PEM fuel cells create electricity through an electrochemical process. The technology consists of three parts; a fuel processor that takes incoming natural gas and converts it to a hydrogen rich stream; a fuel cell stack that takes the hydrogen and uses it to create heat and water; and a power conditioner that turns dc energy to ac energy as used in the home.

The residential PEM fuel cell provides enough base, peak and surge load for a typical single family home. A unit that provides electricity-only is approximately the size of a small, apartment-sized refrigerator, and can be located either just next to, or inside a home.

BACKGROUND:

Fuel cells were actually discovered in 1839 and have been used extensively by NASA for space applications. In recent years, the platinum content in fuel cells has been reduced significantly, which has reduced the cost of the fuel cell to the point of commercial viability. Proton Exchange Membrane (PEM) fuel cells have the ability to operate at lower temperature with faster response and are more reliable than other fuel cell types.

Current electricity-only PEM fuels are undergoing field tests and are expected to be commercially available in 2001. They are expected to reach economic viability shortly thereafter.

WHY DEVELOP A RESIDENTIAL CHP UNIT?

A residential fuel cell that provides power at approximately 40% efficiency is currently in the field test phase of development. Research and development is needed, however to make the unit capable of providing and capturing high temperature waste heat for other processes in the home. Using the thermal energy from a PEM fuel cell can bring efficiencies to as high as 85% by providing the heating, water heating, cooling and/or water chilling. Research and development activities for a residential CHP unit will also be applicable to a 50kW PEM fuel cell unit, such as the one that is currently under development at the U.S. Department of Energy.

PROPOSED RESEARCH AND DEVELOPMENT PROGRAM

Three Year \$24 million Program

At least 60% Private Cost Share

DOE Total Cost Share: \$10 million (2001 - \$4 m, 2002 - \$4 m, 2003 - \$3m)

Private Total Cost Share: At least \$14 million

Congress of the United States

Washington, DC 20515

July 24, 2000

The Honorable Ralph Regula
Chairman
Interior Appropriations Subcommittee
U.S. House of Representatives
Washington, DC 20515

The Honorable Norm Dicks
Ranking Member
Interior Appropriations Subcommittee
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Regula and Ranking Member Dicks:

We are writing today to thank you for your support in the Fiscal Year 2001 Interior Appropriations Bill for stationary Proton Exchange Membrane (PEM) fuel cell funding in the Department of Energy's Buildings Program. We appreciate your inclusion of \$5 million of the President's budget request and urge that you additionally provide \$4 million for the development of a residential combined heat and power unit.

In the last few years, Americans have begun development of PEM fuel cell packages, which create electricity through an electrochemical process. The fuel cell unit provides enough base, peak and surge load for a typical single family home and is approximately the size of a small, apartment-sized refrigerator.

Much effort and funding has gone into developing a cost effective residential fuel cell with electric-only efficiencies of 40%. The real benefit, however, of distributed generation, is the heat that is emitted as they make electricity at the point of usage. This heat can be captured and used for other processes in a home. Diligent work has commenced to develop a single piece of equipment that makes all the electricity, heat and hot water for a typical residential building and can be sited either next to or inside a home. Such a unit would bring overall system efficiency to 80-90% and makes this type of co-generation superior to all other electricity and thermal production.

We understand that work with ties to New York, Michigan, Connecticut, California, and elsewhere has committed to a research and development program that will bring us a combined heat and power unit in the 2003-2004 time frame. We are requesting that the Federal Government, through the U.S. Department of Energy, cost share these developmental efforts. To that aim, we are requesting that \$4 million be added to the Energy Conservation Account of the Fiscal Year 2001 Interior Appropriations Bill for stationary, residential PEM combined heat and power technology development. In conference, we hope that you will give strong consideration to funding R&D for this residential combined heat and power system.

Thank you.

Sincerely,

Joe Knollenberg
Rube
Sherry Buchert
Jared Hall
Michael R. McMurtry

J. Wahl
Mary I. Ackerman
E. Rosen
Ba Gilman
John D. Kennedy

Ehlers
Rivers
Kildee
Dingell

Ideas for Possible Natural Gas/Heating Oil Announcement

What we are doing now:

- CEQ pipeline permitting streamlining process
- Royalty relief for deep wells in shallow water ("Extended Horizons")
- Alaskan statement: Support getting Alaskan gas to lower 48. Commitment that when industry brings forward a proposal for permitting that we will work to coordinate reviews so that they occur as quickly and coordinatedly (this is a new word) as possible.
- Some type of statement regarding inventory of resources.
- Early LIHEAP funds for people to fill heating oil tanks before winter. Ask Congress for more LIHEAP money.

What We Have Already Done

- Established a home heating oil reserve in the Northeast
- We have supported efforts to increase oil and natural gas recovery in the deep waters of the Gulf of Mexico and have conducted a number of extremely successful, environmentally sound off-shore oil and gas lease sales;
- We have opened the National Petroleum Reserve-Alaska (NPR-A) to environmentally responsible oil and gas development, where an estimated 10 trillion cubic feet (tcf) of recoverable natural gas resources lie in the northeast section of the reserve.
- While domestic production of oil overall has gone down since 1989 largely due to the price of oil on the world market, production on Federal and Indian lands has increased and, as of 1999, accounted for 25 percent of domestic production, up from 13 percent in 1992.
- We supported Deep Water Royalty Relief Act (DWRRA) which, along with technological advances, caused leasing in the Gulf of Mexico to increase almost ten fold between 1992 and 1997.
- The Bureau of Land Management (BLM) has taken a number of actions to encourage production on Federal onshore leases as well. Since 1993, BLM has:
 - ✓ Issued over 28,000 leases and approved over 15,000 permits to drill.
 - ✓ Completed an integrated activity plan/environmental impact statement for the northeast portion of the NPR-A. In 1999, the BLM held a lease sale offering 425 tracts on 3.9 million acres -- the first such sale for the reserve since 1984. Oil companies paid more than \$104 million in bids for the high potential oil and gas area
 - ✓ Implemented legislation changing competitive lease term from 5 years to 10 years, allowing lessees greater flexibility in exploration without endangering the lease.
 - ✓ Concentrated its efforts on areas of greatest potential. Assuming requested funds are appropriated, BLM expects to process more than 1000

applications for permits to drill in the Powder River Basin this year with more than 7,000 wells expected in the next five years.

- Our policies also have sought to provide economic relief to Federal onshore operators who have suffered during prolonged periods of low oil prices.
- BLM has provided royalty rate reductions for operators producing heavy crude to offset high costs of production.
- BLM also has provided royalty rate reductions for operators of stripper oil properties (leases producing less than 15 barrels per day) to provide an economic incentive to keep these properties in production. In 1998, a team representing BLM, MMS and DOE completed a study and recommended continuation of the program.
- In addition, BLM and the Forest Service agreed to use one bond to cover liabilities for operations on Forest Service lands, eliminating the requirement that operators buy separate bonding for BLM and the Forest Service.
- At the same time, the agency has taken steps to protect sensitive areas and resources from inappropriate activities, resulting in a policy that has balanced the nation's need for energy with a clean environment.
- Competing environmental analysis of Powder River basin. Estimates of recoverable gas reserves on public lands from this basin alone are as high as 9 trillion cubic feet. If maximum operating capacity of the current pipelines in the Powder River Basin is achieved, production could be as much as 1 billion cubic feet per day. That will produce enough fuel to heat nearly fifty thousand homes in the United States for twenty years. Industry is producing the gas and submitting applications for permits to drill at an unprecedented rate and, presently, there are more than 4,000 coalbed methane wells in the basin. Upon completion of further environmental analysis, we expect to nearly double that amount. We have requested additional planning funds to address the increasing demand for this resource.



American Gas Association

Copy Beier
Goldstein

CHARLES H. FRITTS
*Vice President
Government Relations*

July 31, 2000

Mr. Roger Ballentine
Chairman
White House Climate Change Task Force
734 Jackson Place, NW
Washington, DC 20503

Dear Mr. Ballentine:

Higher heating oil and gasoline prices have been a major public concern this year. During the first part of 2000, the price of natural gas in the spot and futures market has also increased significantly. Because many natural gas suppliers are currently purchasing gas for consumption this winter, it is likely that most consumers will pay more for each unit of natural gas during the 2000-2001 heating season than they did last winter. It is also important to note that supplies of natural gas will be adequate to meet customers' needs.

Enclosed is a recent AGA Issue Brief discussing the potential impact of higher natural gas prices on natural gas customers. It is designed to supply you with factual information that you can use as a resource in responding to inquiries. The Issue Brief provides information on natural gas demand, production and storage and the impact of higher prices on customer bills. A "Frequently Asked Questions" piece and background on the natural gas industry are also included. All of this information can be found in the new "Issue Focus" section of our website (www.aga.org) along with news updates and response mechanism where you can send us your own questions or comments on this issue.

The benefits of the current competitive market for natural gas are numerous. Prior to 1978, the federal government regulated the wellhead price of natural gas sold into interstate commerce. This price regulation resulted in artificial shortages, curtailments and laws banning the use of natural gas in factories and electric generation. Congress wisely chose to deregulate the wellhead price of gas in a phased process beginning in 1978 through 1993. As a result, domestic production has increased, demand has grown, and the real price of natural gas has declined in all sectors. Competition has benefited all types of natural gas customers, from homeowners to factory owners, and clearly has helped the U.S. to reduce its dependence on foreign oil while promoting a cleaner environment.

AGA plans to host a briefing for members of Congress, staff and other government officials on natural gas market conditions in September. (Details to follow.) We also intend to provide you with updated factual information throughout the year.

Finally, AGA encourages the appropriate government agencies to support increased funding for the Low Income Home Energy Assistance program to address the impact of rising energy prices on residential consumers. LIHEAP, currently funded at \$1.1 billion, serves only one in four eligible low-income households. Higher energy prices will stretch LIHEAP resources to the limit.

Please contact me, or Deborah Estes of our Government Relations staff @ 824-7208 if you have any questions.

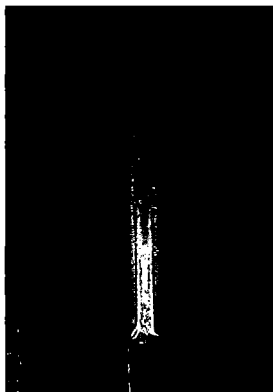
Sincerely,

Charles H. Fritts

Charles H. Fritts

Enclosure

FACTS ABOUT NATURAL GAS –THE FUEL OF THE FUTURE



Natural gas is an abundant, domestic, efficient fuel that provides about one-fourth of all the energy used in the United States. The use of natural gas has increased by 35 percent in the United States since 1986, and is expected to continue to grow by another 45 percent by 2015 – and could grow by as much as 60 percent by 2020 if appropriate federal and state actions are taken.

Natural gas is the cleanest and most efficient fossil fuel. Increased use can help address several environmental concerns, including smog, acid rain and greenhouse gas emissions.

Natural gas utilities employ more than 151,000 people in all 50 states, with an annual payroll of \$6.7 billion.

99 percent of the natural gas used in the United States comes from North America – in sharp contrast to oil and other petroleum products, which are largely imported from overseas.

Local gas utilities serve more than 60 million customers. They have an investment in, and a commitment to, the communities they serve. Many gas utilities have been in business for well over 80 years. This figure includes:

- 55.6 million households (about 54 percent of all American homes use natural gas)
- 4.6 million commercial customers
- 161,900 industrial customers
- 37,000 other customers

More than 70 percent of new single-family homes built today are heated with natural gas.

In all 21.9 quadrillion Btus (British thermal units) of natural gas was consumed in the United States in 1998. To put this in context, 1 quadrillion Btu is roughly the amount of energy needed to power a city the size of Cleveland for a year.

Total natural gas utility revenues were \$46.9 billion in 1998.

Natural gas is delivered to customers through 1.28 million miles of pipeline: 980,800 miles of local distribution pipes, 253,900 miles of transmission (large-volume) pipes and 45,000 miles of field and gathering lines.

Source: 1999 American Gas Association *Gas Facts* (1998 data)

American Gas Association

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American Gas Association

FREQUENTLY ASKED QUESTIONS ABOUT RECENT NATURAL GAS PRICE INCREASES

July 2000

Q: Why are natural gas prices rising? Is this only occurring in certain areas, or nationwide?

A: The price of natural gas is increasing throughout the United States. Like other commodities, such as wheat and orange juice, natural gas prices rise and fall as supply and demand change. Supplies of natural gas are tight temporarily, which has led to higher prices. In a nutshell, here's what's been happening recently:

- **Demand:** The United States has enjoyed a strong economy for the past 7-8 years. As a result, demand for all forms of energy has increased. About 40 percent of the natural gas consumed in the U.S. is consumed by factories and other industrial customers, so on-going economic growth continues to push natural gas demand. Relatively high oil prices have kept many factories and electricity generators from switching from natural gas to fuel oil. While only 15 percent of the electricity generated in the U.S. comes from natural gas, in the future an increasing amount of electricity will come from natural gas because it burns more cleanly than other fossil fuels.
- **Supply (exploration and production):** Almost all of the natural gas consumed in the United States is produced in the U.S. During the past few years (1998 and 1999), the price that producers could get for natural gas was fairly low. This contributed to a decline in the number of rigs drilling for natural gas. This situation has reversed, and more rigs are drilling for natural gas than at any time during the last 15 years.
- **Storage:** Many natural gas utilities purchase gas and store it underground for use during times of strong customer demand. This year, because the price of natural gas was higher in the spring and early summer than it was last year, some utilities had to pay more for their gas supplies. Natural gas utilities are confident that the level of natural gas in storage will be adequate to meet customers' needs next winter, and strive to purchase those supplies at the best possible price.
- **Imports:** It is very exciting that additional pipeline capacity is becoming available to bring additional supplies of natural gas to the U.S. from Canada. During the last 10 years, the amount of natural gas imported from Canada has doubled, and now makes up about 13 percent of the natural gas consumed in the U.S.

Q: Is the natural gas price increase temporary, or permanent?

A: Natural gas producers have boosted their exploration and production activities, so it is anticipated that natural gas prices will moderate when fresh supplies come into the

market. Typically, this could take six, 12 or 18 months. It's possible that natural gas customers will pay more until the end of next winter (2000-2001).

Weather is another important factor in determining how much a customer pays each month for natural gas service. When the weather is cold, residential customers use more natural gas to keep their homes warm – so their gas bills are higher, no matter how much each unit of natural gas costs.

Q: Is there a shortage of natural gas?

A: No! Although supplies of natural gas are tight temporarily, the United States has abundant supplies of natural gas, thanks to a large and diverse resource base. In fact, almost all of the natural gas used in our country comes from the United States and Canada. This is a sharp contrast to heating oil and other petroleum products, more than half of which must be imported to the U.S. from foreign countries.

Q: How do utilities acquire natural gas supplies?

A: A typical local natural gas utility purchases natural gas from North American producers, then resells it to customers without adding any profit. They work hard to obtain supplies at the best possible price for its customers.

Many utilities have standing contracts with several different pipeline suppliers, and can also purchase natural gas on the open ("spot") market. In addition, many utilities store natural gas underground for use during periods of strong demand.

In about 25 states, some or all residential natural gas customers have the option of purchasing their natural gas from non-utility suppliers, often called "marketers." Those companies, too, are trying to get a good price – but they often cannot guarantee that they can get a better price than the local utility.

Q: Why doesn't the utility just absorb the cost increases, instead of passing them along to customers?

A: Natural gas utilities do their best to anticipate changes in natural gas costs and to structure their rates accordingly. Extreme weather conditions or volatility in the commodity price of natural gas can create unexpected shifts in the costs that customers pay. Although residential customers are insulated from rapid ups and downs in the price of natural gas by the purchasing practices of local utilities, bill-payment options and state oversight, these customers must ultimately pay for what they use. Remember – natural gas utilities do not add a penny to the price of natural gas they buy for residential customers; they simply pass the costs through.

Some utilities use financial techniques -- such as weather risk insurance -- to help control the price of gas for their customers.

Q: What can customers do?

A: Customers have several options:

- Conserve energy. During the summer months, homeowners may wish to arrange for an inspection of their home appliances – especially heating and water-heating equipment – to make sure they work efficiently and safely. Some may also want to get a home energy audit, which will pinpoint ways to make the home more energy-efficient (such as adding storm windows or sealing drafty doors).
- Replace aging appliances. Consumers who have aging natural gas furnaces and water heaters should consider replacing them with new units, which use fuel more efficiently. High-efficiency units cost more to buy, but they save money over the long run. For example, by buying a high-efficiency (93 percent-efficient) natural gas furnace instead of a conventional unit (78 percent efficient), an average homeowner could save \$135 per year in energy bills – that's \$1,350 over the 10-year life of the equipment. (*SOURCE: American Gas Association press release, Feb. 14, 2000.*)
- Check out bill-payment options. Most utilities offer easy-payment plans, which help to even out the amount of each month's natural gas bill. This may be particularly helpful to individuals with fixed incomes.
- Request special assistance. Customers who truly cannot afford to pay some or all of their natural gas bills should contact their local natural gas distribution company for information about the Low Income Home Energy Assistance Program (LIHEAP), fuel fund assistance and other programs.



American Gas Association

FYI

400 N. Capitol St., NW, Washington, DC 20001 ■ <http://www.aga.org>

CONTACT: Peggy Laramie and Daphne Magnuson
(202) 824-7211

June 2000
FYI-9

Natural Gas Price Trends

Weather is a strong factor in determining natural gas prices, and every winter heating season is unique. The 1999-2000 winter heating season, like the preceding one, featured mild weather conditions and a natural gas delivery system that was for the most part unchallenged by the rigors of sustained cold temperatures. Several weeks of colder-than-normal conditions in October 1999 soon gave way to warm weather patterns.

Despite differing weather patterns from one year to the next, local natural gas utilities are well prepared to continue providing a reliable supply of natural gas to households and other customers.

The price paid for natural gas by consumers depends on the price of the gas commodity itself, and the cost of transporting that gas from production areas to customers. Although previously regulated, the price of the gas commodity was deregulated during a 15-year period, beginning in 1978. Federal and state officials have retained the authority to regulate the costs of transporting and distributing natural gas; these costs account for approximately two-thirds of a residential customer's bill for gas service.

It is helpful for consumers to understand the difference and the relationship between various types of natural gas prices, such as "wellhead" gas prices and residential gas prices. An increase in wellhead prices does not necessarily mean a correlating or immediate increase in residential prices. Here's an explanation of different types of gas prices:

Residential Prices:

Rates for residential natural gas service are regulated by state agencies, usually called public service commissions or boards. Some states appoint regulators; others elect them.

Residential natural gas rates are for natural gas service, not just the gas commodity. The price of the gas commodity makes up about one-third of the total price a residential customer pays, on average. The remainder of the customer's bill includes amounts for the transmission and distribution of gas, system maintenance, safety and inspection programs, customer service, metering, billing and other costs.

Natural gas utilities do not add any profit margin to the price they pay for gas. Their customers normally do not pay any more for gas than the utilities do. Put another way, the natural gas utility does not make or lose money on the commodity cost of gas.

The adjustments for the rise and fall of the gas commodity price vary by state. Some states require monthly "purchased gas adjustment" or "cost of gas adjustment" filings. Others are quarterly or based on a six-month average. The more frequent the adjustment, the sooner residential prices will reflect the actual upward or downward movements of the price paid by the LDC for the gas it delivers.

Changes in the prices paid by utilities for gas, whether based on futures prices, the spot market or the comparative price of other fuels, do not have an immediate impact on residential gas customers because of the structure of regulation and the industry. This is true for several reasons. Utilities' gas supply portfolios are diversified among spot purchases, long-term contract gas, storage gas, peak-shaving gas and other sources, so price spikes in one arena do not have an immediate impact on residential customers. Moreover, state regulation of gas cost recovery generally tends to spread out short-term increases or decreases over time. As a result, only more sustained trends influence residential gas prices to any significant degree.

Wellhead Prices:

The Natural Gas Policy Act of 1978 began a process that ended federal control over the wellhead price of "new" gas on Jan. 1, 1985, but kept in place price controls for gas produced from wells drilled prior to 1977. In 1989, the Natural Gas Wellhead Decontrol Act of 1989 lifted all remaining wellhead price controls on natural gas. As a result, there are no remaining federally mandated natural gas wellhead prices.

The most important factor affecting natural gas wellhead prices is the competitive marketplace. Factors that affect gas prices include the weather, overall gas demand, the prices of competing fuels (primarily coal and oil) and competition between gas companies for the supplies.

Spot Market Prices:

One segment of the gas market has been dubbed "the spot market." Transactions are generally for only a very short duration and can be rearranged quickly if prices change. The spot market developed in the early and mid-1980s, when long-term contracts fell into disfavor and there was a substantial supply of gas available. Newly developed gas supplies and gas that was turned back by pipelines were usually sold at lower prices than the gas pipelines purchased under long-term contracts.

With the restructuring of the industry, a robust spot market for short-term gas supplies continues to flourish. Spot market prices fluctuate, based on the availability of supplies. The gas supply portfolios of most natural gas utilities do not rely exclusively on spot market transactions, depending on the time of year. In case of unexpected demand surges, utilities and other customers may be forced to purchase spot market gas, which under these circumstances is frequently sold at a higher price than the long-term contract gas.

Futures Prices:

Natural gas futures contracts began trading on April 3, 1990, on the New York Mercantile Exchange (NYMEX). Sabine Pipe Line Co.'s Henry Hub near Erath, La., an interconnection of seven interstate and three intrastate pipelines, is the delivery site for contracts.

A futures contract is based on the value of about 10 million cubic feet of natural gas. These contracts are not generally used as a vehicle to acquire gas supplies, but rather are financial instruments that allow sellers and buyers of gas to minimize their financial risk. Like virtually all commodity markets, most contracts are liquidated by offsetting an obligation to sell gas with an equal obligation to buy gas. Thus only a small quantity of gas is ever actually delivered to Henry Hub.

Natural gas futures prices and natural gas spot market prices have a relationship, but it is difficult to say which influences which. The futures price, the spot price and the price of competing fuels all work to reflect competition in the market. Futures prices for natural gas and other commodities are more volatile than other gas prices because they react instantly to news, rumors and other market factors.

Price Indexing

Some natural gas prices are contractually agreed upon to reflect changes in the spot, futures or other markets, such as heating oil. Price indexing is used in a number of cases to reflect that the parties to the contract believe the price to be paid is related in some fashion to the index used. It is difficult to determine how many natural gas contracts between producers and customers have such clauses. It should be noted that gas contracts are private between the buyer and seller and generally are not publicly available, so that any estimates of contract terms or volumes of gas with price clauses are, at best, an educated guess.

Pipeline Transportation Prices:

The Federal Energy Regulatory Commission (FERC) regulates the rates, terms and conditions of service provided by interstate natural gas pipelines. FERC issued its "restructuring" rule, Order 636, in April 1992. The policy goal of Order 636 was to separate the transportation of gas from the sales of gas, and to put all natural gas suppliers and gas purchasers on an equal footing. Order 636 required pipelines to separate their gas sales services from their transportation services. Pipelines must now provide all transportation services on an equal basis, whether the gas being transported is purchased from the pipeline, pipeline marketer or another gas supplier. The rates that pipelines charge for their services, however, are still regulated by FERC.



American Gas Association

Policy Analysis Issues

POLICY ANALYSIS GROUP
400 N. Capitol St., NW
Washington, DC 20001
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IB 2000-04

June 30, 2000

THE POTENTIAL IMPACT OF HIGHER NATURAL GAS PRICES ON RESIDENTIAL CUSTOMERS

Introduction

During the first part of 2000, the price of natural gas in the spot and futures markets has increased significantly. Because many gas suppliers are currently purchasing some gas for consumption this winter, it is likely that most consumers will pay significantly more for each unit of natural gas this winter than they did last winter.

A number of factors influence the price of gas in the marketplace:

- **Natural Gas Production** -- Low wellhead prices in 1998 and into 1999 contributed to a decline in the number of working rigs drilling for natural gas. The situation has reversed and rig counts are now well above the levels of the same period last year. However, due to the historic time lag between increased drilling activity and a price response, it is unlikely that this increased drilling will have a significant impact on consumer bills this winter.
- **Natural Gas Underground Storage** -- Natural gas storage levels have been significantly lower this year than at the same time last year but only somewhat lower than the average for the past five years. All indications are that they will be up to targeted volumes by the onset of the winter.
- **Natural Gas Imports** -- Natural gas imports from Canada have grown well over 100 percent in the last decade, currently accounting for about 13 percent of U.S. gas consumption. Canadian imports are expected to continue to grow incrementally with U.S. demand growth.

- **Natural Gas Demand** -- During the last decade demand for natural gas has increased in all sectors at an average rate of 2.8 percent per year. Forty percent of the natural gas consumed in the U.S. is used by factories and other industrial customers (including cogenerators), so the ongoing economic growth continues to push natural gas demand. Gas-fired electricity generation from electric utility plants and IPP's is a smaller (approximately 15 percent) but faster growing component of gas demand. Data is not yet available to quantify the magnitude of the impact of the electricity generation market on current natural gas demand. Relatively high oil prices have kept many factories and electricity generators from switching from natural gas to fuel oil.

Impact of Higher Gas Prices on Consumer Bills

In understanding the possible impact of these current natural gas prices, it is important to keep the following in mind: weather is a key variable affecting residential gas bills during the winter heating season. Thus, a return to normal weather (from the mild levels of the winter of 1999-2000) – even if natural gas prices were unchanged from their relatively low levels last year – would increase consumers' heating bills. Consumers should expect significantly higher natural gas bills if the present increase in gas commodity prices combines with higher gas consumption due to colder (but normal) weather.

Almost all local natural gas utilities do not add any profit margin to the price they pay for each unit of natural gas. Their customers normally do not pay any more for gas than the utilities do. On average, the cost of gas makes up about one-third to one-half of a residential customer's bill. Therefore, an increase in the cost of the gas itself produces a lower overall percentage increase in the customer's total bill. The remainder of the customer's bill for service includes amounts for the transmission and distribution of gas, system maintenance, safety and inspection programs, customer service, metering, billing and other costs. It should be noted that state public service commissions regulate the prices that local natural gas utilities charge.

- In many states purchased gas costs for gas utilities are averaged over a season or even a year and passed on to consumers as an average cost of gas. This does not mean that the purchase price for a gas utility's gas supplies cannot increase unexpectedly. What it does mean is that a particular spike in gas prices for a day or week or even months may be mitigated by the averaging of costs over the year.
- Consumers should not attempt to estimate their monthly natural gas bills based on fluctuations in the daily "spot" prices of natural gas. Daily spot prices are not indicative of average gas costs to consumers because only a portion of all gas supplies (particularly during seasonal peaks) is purchased in the daily market. The majority of supplies are purchased under monthly, multi-month or even multi-year contracts. Some prices in these agreements are tied to various indices, while others are fixed.

- Gas utilities use a portfolio approach for winter heating season and other gas purchases. Many companies employ a pricing strategy that includes a *basket of indices* from first-of-the-month to multi-month fixed price schedules. During the 1999-2000 winter heating season peak-day, companies in AGA's annual Winter Heating Season Survey indicated that over 90 percent of their gas purchases were made in a form other than daily spot purchases and were, therefore, not subjected directly to daily spot price volatility.

Source: *Monthly Energy Review*, Energy Information Administration, U.S. Department of Energy.

Natural Gas Production

- Almost all (87 percent) of the natural gas used in the United States is produced in the United States. Most of the remainder (about 13 percent) comes from Canada. Natural gas production in the U.S. grew 9 percent from 1990 to year-end 1998 (17.2 Tcf annually in 1990 to 18.7 Tcf in 1998). Imports of natural gas to the U.S. from Canada grew 111% percent during the same time period, from 1.4 Tcf in 1990 to 3.1 Tcf in 1998.
- According to the Department of Energy's Energy Information Administration (EIA) the last year-to-year U.S. production increase came in 1997 (0.3 percent greater than 1996). Natural gas production in 1998 was down 1.1 percent, and 1999 down 0.3 percent. However, year-to-date estimates through May 2000 (*Natural Gas Monthly*, May 2000) showed domestic gas production to be 0.7 percent greater than January-May 1999 production.
- According to EIA, average wellhead prices were below \$2.00 per Mcf (thousand cubic feet) for nine straight months, August 1998-April 1999. As a result, by April 1999 most production indicators were very low -- that is, rigs drilling for gas were down to 371 monthly average, while gas well completions were only 656 for the month. Beginning May 1999, prices climbed above \$2.00 per Mcf and have been there since. In response to the wellhead price increase, natural gas exploration and production have improved dramatically. (See Figure 2 - Gas Directed Drilling Activity and Crude Oil and Gas Prices.) By October 1999 (after about five months of gas prices above \$2.00), more than 600 rigs were drilling for natural gas -- a more than a 60 percent increase from five months earlier -- and have essentially remained at that level. Gas well completions also increased and have been greater than 1,000 per month since October 1999 (a 30+ percent increase).
- These increases in drilling indicators point to an expectation that domestic production capability will remain strong and resilient in the foreseeable future and that price signals in the marketplace will encourage additional drilling, which will in turn produce downward pressure on prices over time. However, historic experience indicates that there is a time lag between increased drilling and a significant price response. Therefore, price reductions resulting from an increased level of drilling may not be realized in the upcoming heating season.

Sources: *Preliminary Findings Concerning Natural Gas Reserves*, American Gas Association.
U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, Energy Information Administration, DOE.
Natural Gas Monthly, April 2000.

Natural Gas in Underground Storage - This Year Compared to a Five-Year Average

Supplies of natural gas held in underground storage are only somewhat below the five-year average for this time of year (mid-June). As shown in the attached chart (Figure 1), working gas inventories as of June 23, 2000, were only 10 percent less than the five-year average (1995-1999). A comparison of current storage levels (1,567 Bcf as of June 23, 2000) to levels of a year ago (2,033 Bcf on June 25) can be misleading. In 1999 storage levels in June were unusually high, due to the warmer-than-normal winter of 1998-1999 and unusually low early summer natural gas prices that encouraged purchases for injection. In fact, the storage level today exceeds the levels on this date in both 1996 and 1997.

- Working gas in storage actually exceeded the five-year average for 10 of the first 15 weeks this year. However, early season injection rates are beginning to trail the five-year average, according to the American Gas Storage Survey. It is too early to tell what impact storage injection requirements, summer electric generation load, production deliverability and commodity prices will have on summer underground storage refill.
- It should be noted that the Consuming Region East (the most heating-load sensitive region) has ended the winter heating season as little as 9 percent full (April 1996) and as high as 31 percent full (April 1999) based on records back to 1994. In every case and under significantly different price and demand conditions, summer injections have resulted in working gas levels that were 95-99 percent full by November, the traditional start of the winter heating season.

Source: *American Gas Storage Survey*, American Gas Association.

Natural Gas Imports

- Natural gas imports from Canada have exceeded 3 trillion cubic feet (Tcf) for two consecutive years and currently account for about 13 percent of the gas consumed in the U.S. This trend is expected to continue with Canadian imports growing incrementally with U.S. demand growth.
- Recent additions to pipeline capacity moving Canadian gas to U.S. markets has added supply flexibility for U.S. consumers. The Northern Border Expansion, production from Sable Island (offshore eastern Canada) and the expectation that new gas supplies will begin flowing to Midwest markets through the Alliance pipeline in mid-November 2000 are representative of the new supply additions.

Conclusion

Natural gas is a clean, safe, efficient and reliable fuel, which is why the market is demanding natural gas, and why demand from all customer sectors is increasing. Recent fluctuations in natural gas prices indicate that market forces are attempting to balance supply and demand.

The North American natural gas resource base is ample to supply the growing market.

Figure 1

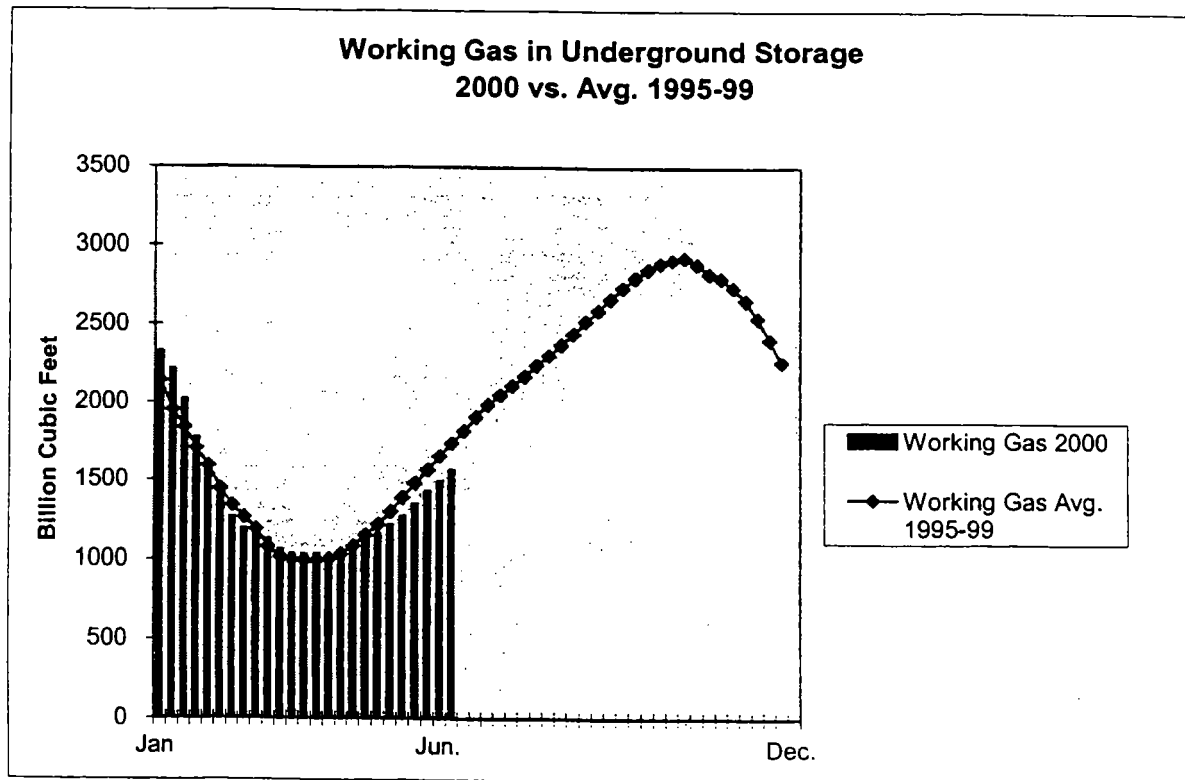
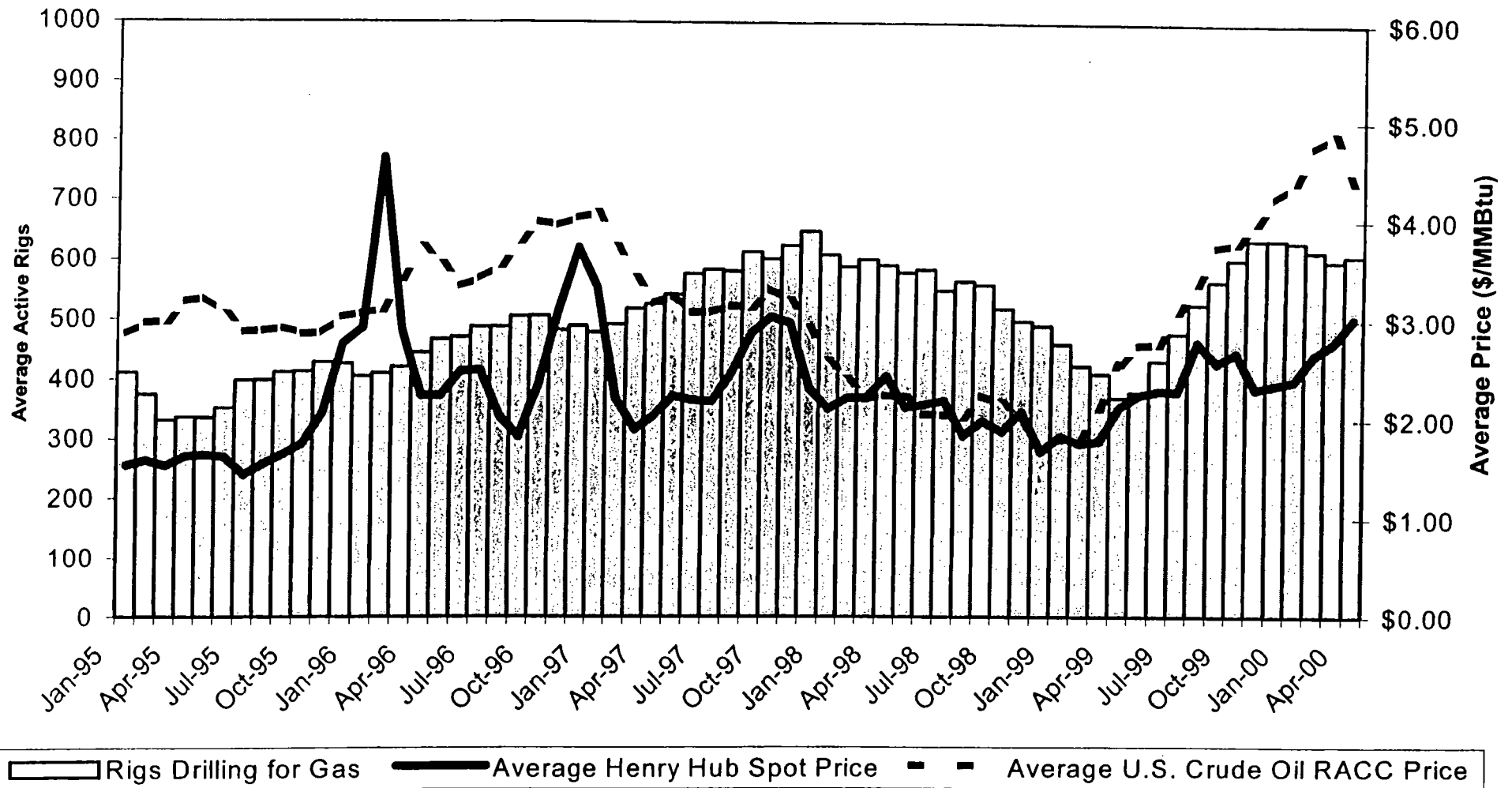


FIGURE 2

Gas Directed Drilling Activity and Crude Oil and Gas Prices





American Gas Association

Policy Analysis Issues

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NATURAL GAS SUPPLY FUNDAMENTALS JUNE 2000

Introduction

Commodity prices -- first for heating oil during the 1999-2000 winter heating season and then for natural gas during the spring and summer refill of underground storage -- have been scrutinized endlessly regarding their rise to relatively high levels. For natural gas, the sustained wellhead price of over \$3.00 per mcf since March 2000 has led to questions about the strength of natural gas supplies, particularly in the face of anticipated seasonal electric generation demand from gas-fired merchant facilities.

In reality, it is difficult to quantify the actual level of incremental demand for natural gas being created by existing peaking plants. However, it is clear that the natural gas marketplace believes that natural gas supplies are being tested by demand growth from a robust economy and has reflected that in \$4.00 per mcf (and more) daily spot prices and futures contracts. The question remains -- what is the status of US natural gas supplies and what is the expectation for the balance of 2000?

The following summary reviews key national gas supply indicators and points to strong natural gas supply fundamentals for 2000. Expectations for the current year include a diverse gas supply base, growing domestic productivity, increases in gas directed rig activity, more gas well completions than in 1999 and additional gas imports from Canada. Each of these factors portends adequate natural gas supplies for firm gas customers during 2000 and beyond to the next winter heating season.

Natural Gas Supply Summary

	1990	1998	Est. 2000
Natural Gas Resources (Tcf)	1,002	1,037	1,030

Virtually any group that studies potential gas resources in the United States and North America recognizes that the resource base is vast and diverse. In addition, perceptions and estimates of gas resources grow as technology and economics impact estimation psychology. According to the Potential Gas Committee estimated resources grew nearly 20 percent from 1990 to 1998 inasmuch as year-end 1998 resources (1,037 Tcf) were greater than in 1990 (1,002 Tcf) even though over 160 Tcf was produced during the period 1990-1998. Technology is expected to continue to have an impact on the identification and development of undiscovered natural gas resources

	1990	1998	Est. 2000
Natural Gas Reserves (Tcf)	169.3	164.0	163.5

Natural gas reserves by definition are associated with known quantities of gas tied to well activity and serve to identify a "shelf inventory." That inventory has been at about 9 years of reserves during the 1990s. As is the case with natural gas resources, reserves have changed little since 1990, even though over 160 Tcf has been produced from domestic inventories. This near 100 percent replacement of produced gas on an annual basis through new gas additions and revisions of prior estimates serves to reinforce the idea of a large and diverse resource base from which gas reserves can be developed given the appropriate economic incentives.

	1990	1998	Est. 2000
Non-Producing Gas Reserves (Tcf)	35.1	36.0	36.0

Non-producing gas reserves can be an indicator of potential new gas deliverability that may be made available in a relatively short period of time. Non-producing reserves are designated as such because wells may be waiting for workover rigs in order to finish well completion tasks; pipeline facilities may not be installed; and/or additional zones in a producing well may be waiting for the opportunity to produce, while other zones become depleted and the new zones can be efficiently readied for production.

Natural Gas Supply Summary (Cont.)

	1990	1998	Est. 2000
Domestic Gas Production (Tcf)	17.2	18.7	18.9

Annual domestic natural gas production has grown 1.5 Tcf since 1990. Producers are more efficient in developing gas properties, however, are sensitive to perceptions regarding sustained wellhead prices. Strengthening wellhead prices beginning in 1999 have led to substantial increases in key drilling indicators, such as gas rigs operating and gas well completions, and support expectations for increased gas deliverability for 2000 over the previous year.

	1990	1998	Est. 2000
Gas Rigs Operating	464	496	600+

Gas rig operations have changed dramatically since 1990. In 1990, more rigs on average drilled for oil than drilled for gas. By 1999, seventy-nine percent of all rigs operating were drilling for gas (496 of 625 rigs). Drilling fundamentals in 1999 were impacted by relatively low (below \$2.00) wellhead gas prices, but by year's end supported over 600 rigs drilling for gas. If the average remains at above 600 rigs operating for 2000, it will be the highest level of gas directed activity since 1985.

	1990	1998	Est. 2000
Natural Gas Well Completions	11,044	10,513	11,500+

In 1990, more wells were completed as oil wells than gas wells. By 1999, gas well completions exceeded oil well completions by more than 6,000 and reflected a similar growth in gas rig activity. Gas well completions are expected to be strong in 2000 as a result of relatively high average wellhead prices for the year.

	1990	1998	Est. 2000
Working Gas in Storage (Tcf)	3.1*	3.0	est. 2.9

Natural gas in underground storage entering the winter heating season has varied from 2.7 to 3.1 Tcf since November 1994 according to the American Gas Storage Survey. Gas has been added to storage (primarily during summer months) under many different conditions of seasonal prices and cooling demand and has been extracted under similar variations in weather induced winter heating season requirements. In all cases, sufficient volumes of gas in storage have been available for customers.

Natural Gas Supply Summary (Cont.)

	1990	1998	Est. 2000
Canadian Imports (Tcf)	1.4	3.3	3.4
<i>Natural gas imports from Canada have grown dramatically since 1990, reflecting the development of a truly North American gas market place. Both production capability and pipeline capacity to the US continue to increase. Recent deliveries of gas from Sable Island (eastern Canada offshore) to the US northeast and the start-up of the Alliance Pipeline (delivering supplies from the western sedimentary basin to the US Midwest) are examples of the growing potential for Canadian gas in the expanding US gas market.</i>			

	1990	1998	Est. 2000
Liquefied Natural Gas (Bcf)	84	159	160
<i>Imports of LNG have traditionally been sensitive to domestic natural gas prices and tend to increase when gas prices increase. Suppliers of LNG to the US have diversified to include not only Algeria but also Australia, Qatar, Trinidad and Tobago and the United Arab Emirates.</i>			

	1990	1998	Est. 2000
Other Supplementals (Bcf)	123	95	100
<i>Supplemental gas sources include propane-air, LNG created from pipeline supplies and even synthetic natural gas (SNG). Although a small volume when compared to other supply sources, supplemental gas supplies often fill a critical niche during peak demand periods or provide a source for gas where another is not available.</i>			

	1990	1998	Est. 2000
Pipeline Capacity (Bcf/d)	73.7	88.4	+12.5**
<i>Pipeline capacity and additions to storage develop based on the demands of a growing and competitive gas market. Connecting new gas supply basins and aggregation points with burgeoning market areas has resulted in new pipeline construction proposed and built in virtually every region of the US during the past 10 years. Expansion of existing pipeline corridors and new construction will continue beyond 2000, as natural gas consumption patterns, available capital and market opportunities dictate.</i>			

*Represents November 1994. Weekly American Gas Storage Survey not available prior to December 31, 1993.

**Increment of additional pipeline capacity proposed for completion 1998-2000.

Sources: American Gas Association, Energy Information Administration and Potential Gas Agency.

GAS SUPPLY RESEARCH ROYALTY TRUST FUND

Present Law

In 1998 the U.S. Government under the royalty payments system managed by the Minerals Management Service of the Department of Interior received approximately \$3 billion in royalty payments from oil and gas production on federal land, of which \$1.7 billion was derived from royalty payments on gas production.

Proposed Change

Companies that produce oil and gas on federal lands would be provided an option to designate that 10 percent of their royalty payments from gas production on these federal leases (after deducting for state shares) would be directed to a Gas Supply Research Trust Fund. No change is proposed in the current oversight and management of the royalty system by MMS. Release of these trust funds to an Industry operating agent (501(c)(3) not-for-profit organization) would be made on an annual basis contingent on the review and approval of an annual research, development, and demonstration (RD&D) program and a 5-year RD&D plan by a gas producer steering committee and then by a joint Federal/Industry Board.

Role of Independents

Approximately 8,000 independent producers are currently active in the U.S.; they drill 85 percent of wells in the 33 states with oil and gas production and produces 65% of U.S. gas. Forty-six percent of independents currently hold Federal leases.

Independent producers are critical to the continued development of gas production. Independents rely on collaborative research performed by not-for-profit gas industry (501)(c)(3) research organizations such as Gas Technology Institute (GTI). In the past GTI has funded through its FERC approved research programs, \$60-\$70 million annually of gas supply research focused on the collaborative research priorities of the gas producers. The GTI FERC approved research program will be phased-out in 2004. Therefore, the Gas Supply Research Trust Fund would provide the companies producing gas on federal leases the opportunity, at their option, to continue to participate in collaborative research on technology to increase future gas production on federal lands.

Technology Transfer

To ensure the most cost-effective and efficient transfer of the technology resulting from the research, the National Office of the Petroleum Technology Transfer Council and the Technology Transfer Agents of GTI and the Regional independent producer associations will be used.

Policy Implications

Investment in technology to increase domestic production of natural gas has important national benefits. Increased production and use of natural gas reduces our dependence on imported oil, has fewer environmental consequences than using other fossil fuel, and results in greater economic activity for U.S. industry and its citizens. Furthermore, greater efficiency of production of natural gas from a wider range of available resources on federal land through reinvestment in improved technology results in greater revenue to U.S. Government through increased production and total royalty payments and should be an essential feature of a sound energy policy.

Status

Briefings have been made to IPAMS, TIPRO, IOGCC, and IPAA Offshore Committee. The Louisiana Independent Oil and Gas Association was briefed on July 18.

Next Steps

Meetings with DOE and White House staff to discuss Administrative support. Briefings to KIOGA and Oklahoma Independent Producers scheduled.

Hydraulic Fracturing

Underground Injection Control (UIC) Program

ISSUE: In 1997 an 11th Circuit Court decision required that EPA ensure that Alabama regulate hydraulic fracturing of wells producing methane from coal beds, or withdraw Alabama's UIC program. What is the status of this issue? What is EPA's current position on the proposal of a legislative exemption for hydraulic fracturing from definition as an underground injection?

TALKING POINTS:

- In December 1999, EPA approved the revision of Alabama's Class II Underground Injection Control (UIC) Program (oil and gas) to regulate hydraulic fracturing¹ of coal bed methane wells.
- This satisfies the 11th Circuit Court *mandamus* order and EPA will not need to withdraw Alabama's primary enforcement authority for the UIC Class II program.
- The Legal Environmental Assistance Foundation (LEAF) is challenging the Agency's approval of the Alabama revisions.
- Regarding the proposal of a legislative exemption for hydraulic fracturing, we believe that any decision concerning the potential future regulation of hydraulic fracturing activities should not be made until we are fully informed of any potential risks to drinking water sources and we hear from all involved stakeholders.

BACKGROUND:

- The oil and gas industry is concerned that the Court's decision may lead to national regulations for all hydraulic fracturing practices including all oil and gas wells. Senator Inhofe has introduced legislation to prohibit EPA from regulating any hydraulic fracturing. The Alabama Congressional delegation has also been involved in this issue. Both House and Senate Appropriations Committees have members from Alabama (Rep. Robert E. [Bud] Cramer, Jr. and Sen. Richard Shelby).
- In the FY 2000 budget, the Geological Survey of Alabama was authorized to receive \$175,000 to perform a study on the effects of hydraulic fracturing on public water supplies. EPA intends to review the results of that study and has set aside resources for focused nationwide investigations beginning this year to assess the risks posed to drinking water posed by this practice.
- During the past two years, EPA has received citizen complaints that coal bed methane gas production has negatively impacted drinking water wells located near coal bed methane well fields. EPA followed up on citizen complaints. Environmental problems appear to be related to the dewatering of formations during coal bed methane development, rather than hydraulic fracturing. However, some citizens contend that hydraulic fracturing has resulted in water loss and

¹Definition of hydraulic fracturing: high-pressure fluid injection through a wellbore to create fractures in a geologic formation, allowing fluid to flow more easily and at an increased rate.

water quality degradation.

- The Ground Water Protection Council (GWPC) conducted a survey in 1998 of selected agencies within oil and gas producing states. The report indicated no substantiated cases of ground water contamination from coal bed hydraulic fracturing.

INFORMATION ON HYDRAULIC FRACTURING

1.0 Overview

The purpose of this document is to provide background information on hydraulic fracturing and related well stimulation processes used by the domestic oil and gas industry to enhance recovery of oil and gas. While hydraulic fracturing occurs in both oil and gas wells, the majority of hydraulic fracturing activities that use significant (over 75 percent) volumes of fracturing fluids occur in the development and production of the domestic gas resource; thus the focus here is on natural gas. The other major well stimulation process, acid treatment, is used widely in both oil and gas wells.

Briefly, the information collected indicates that:

- * The geological formations primarily associated with gas wells that must be hydraulically fractured to be commercially viable occur widely across the country;
- * A significant amount of domestic gas production today is the result of wells developed using hydraulic fracturing;
- * Fracturing a well is not a one time activity, but is often performed on a well periodically over its productive life;
- * Hydraulic fracturing (and similar activities) are projected to increase significantly in the future; and
- * Well acidization is a widely used activity in all oil and gas wells; nearly all wells in the U.S. experience some type of acid treatment over their life.

The remainder of this document provides a general overview of the two most prominent well stimulation activities in the U.S.: hydraulic fracturing and acidization. Details are provided on the composition of the fluids used, waste generated, estimates of the number of wells fractured and acidized as well as their general distribution, and contamination of ground water by well stimulation activities.

2.0 Characterization of the Process

Oil and gas wells are often stimulated to increase the flow of oil and gas resources from the formation to the wellbore. Well stimulations occur for two reasons: 1) either the productivity of the well itself has diminished over time as scales and sludges accumulate in the wellbore; or 2) the geological formation containing the oil and gas reserves inhibits the flow of the resource to the wellbore. Acid treatments are primarily used to address the first issue; while hydraulic fracturing primarily is used to address the second. The majority of hydraulic fracturing activities occur in low permeability, or unconventional gas reservoirs. In these unconventional reservoirs,

specifically coal beds, low permeability (tight) gas sands, and Devonian-age gas shales, the natural pore spaces of the formation are small and relatively unconnected, such that the pressure in the reservoir is insufficient to drive the gas from the formation to the wellbore. In these reservoirs it is necessary to stimulate the production wells using hydraulic fracturing techniques because the resource will not flow naturally to the wellhead.

2.1 Hydraulic Fracturing

Hydraulic fracturing entails the use of high pressure pumps to force water down the well and into the gas-bearing formation to fracture and improve the flow characteristic of the formation. Once the formation is sufficiently fractured, a slurry is pumped down the wellbore into the new cracks to keep them open when the injection pressure is relieved. This slurry is primarily composed of sand and a guar gum gel, but depending on well and formation conditions, can contain numerous other chemicals as well. The gel is used for its thickness and viscosity to carry the sand into the cracked formation. The gel is compatible with nearly all reservoir fluids and conditions and naturally degrades after performing its function. The sand, called a proppant, is used to hold the fracture open after the gel degrades to allow free passage of the resource to the wellhead. Sand is the most common proppant material, but glass beads, silica, quartz, graphite, nut shells, or similar particles are also sometimes used as a proppant.

While a well operator has the ability to control the extent of a fracture, hydraulic fracturing typically occurs only when the formation is bordered by denser geology to ensure that the fracturing is contained within the gas-bearing formation. A well fracture can extend vertically throughout the entire formation and can extend horizontally several hundred feet. At depths less than 1,500 feet, fractures are typically horizontal, because it is easier to lift the overburden than fracture the formations vertically; that is, the stresses are lower in the vertical than in the horizontal direction. In deeper formation, the opposite tends to be true; and the fractures propagate more generally in the vertical direction. Hydraulic fracturing can be used on almost all formations, and is sometimes combined with acid treatments. Over time the fractures tend to compress due to natural formation pressures, and wells often must be refractured periodically (e.g., every few years) to maintain productivity. Fracturing a well is an expensive process that can cost between \$15,000 and \$250,000, representing from 20 percent to 50 percent of total well cost.

2.2 Acid Treatments

Many oil and gas formations in the U.S. often require acid treatments primarily to increase the flow of oil or gas to the wellhead. Acid treatments generally utilized fall into three categories: 1) acid washing; 2) matrix acidizing; and 3) acid fracturing.

- * **Acid washing** is designed to remove scale and debris present within the wellbore and to open perforations. This involves placing a small amount of acid at a distinct location within the wellbore to remove the accumulated scale from the wellhead or to dissolve part of the formation.

- * **Matrix acidizing** involves forcing acid into the formation pores at a pressure below which the formation might fracture. This is intended to enlarge the pore spaces directly next to the wellbore and to dissolve material plugging these spaces. This method is used in formations where the formation cannot be broken or the natural flow boundaries cannot be disturbed.
- * **Acid fracturing** is a process that entails pushing the acid fluids into the formation under high pressure at a fast rate. The acid dissolves part of the rock and forces the formation to fracture or enlarges existing fractures. The acid most commonly used in this process is hydrochloric acid, which reacts with and dissolves limestone and other carbonate rocks.

Each of the above methods is commonly used to create larger pore spaces and increase the resource recovery from the well. Acids are sometimes used for other productive purposes including use as a spearhead to dissolve fine particles formed in the perforating process, to break emulsions in the formation, to break acid-sensitive gels used in fracturing, and as a preflush before squeeze cementing.

2.3 Background

Increasing well productivity through these types of stimulation methods is not new. Acidizing was reported to have been used as early as 1895, but modern methodologies began around 1932. Hydraulic fracturing was introduced in 1947 and has since become common practice. By 1981, more than 800,000 fracturing treatments had occurred, and by 1988 there had been more than one million.¹ About 35 to 40 percent of wells currently drilled are hydraulically fractured at least once during their lifetime. Approximately one billion dollars is spent annually, worldwide, on hydraulic fracturing treatments to oil and gas reservoirs.²

The U.S. Geological Survey estimates that from 200 to 400 trillion cubic feet (Tcf) of natural gas resource exist in unconventional settings in the U.S., with a mean estimate of 308 Tcf.³ Many research laboratories are conducting fracturing studies and experiments to improve stimulation techniques to more cost effectively produce gas resources in these unconventional settings. For example, DOE's Office of Fossil Energy is co-funding the Fracturing Fluid Characterization Facility on the University of Oklahoma campus. Research at this facility is directed toward studying how hydraulic fracturing actually performs under simulated field conditions. Also, the CER Corporation, with DOE and GRI sponsorship, has a site in Rifle, Colorado where improved hydraulic fracturing techniques are tested. The site is currently using mapping and surveying studies to detect natural fractures and monitor the flow through them.

¹Gidley, John. Recent Advances in Hydraulic Fracturing, Monograph Vol. 12 1989.

²<http://apollo.osti.gov/html/fe/oufrac.html>

³1995 National Assessment of United States Oil and Gas Resources, U.S.G.S., Circular 1118, U.S. Government Printing Office, Washington, DC, 1995.

3.0 Composition of Fracture Fluids

The composition of fluids used for fracturing and acidizing differs depending on formation characteristics. The majority of fracturing fluids and additives are intended to possess the following characteristics: low fluid loss to obtain the desired penetration with minimum fluid volumes, adequate effective viscosity to create the necessary fracture width and carry the proppant, no excessive friction, good temperature stability, good shear stability, minimal damages to formation permeability, minimal plugging effects, good post treatment degradation and removal characteristics, and low cost.

Fracturing fluids can be divided into three main categories: 1) oil-based fluids; 2) water-based fluids; and 3) mix-based fluids. Water-based fluids are the most common and include the guar gel mentioned above. The proppant material used in water-based fluids also varies based on the specific characterization of the underground formations as well as operator preferences. Sand such as silica is the standard proppant, but sintered bauxite is sometimes substituted because of its high strength.

During acidizing, many fluids may be used in succession. Preflush fluids may be pumped into the well first to separate drilling muds or formation fluids from treatment fluids. They may also be used to inhibit corrosion, remove scale, or for other functions. Acid solutions can be divided into five main categories: 1) mineral acids; 2) dilute organic acids; 3) powdered organic acids; 4) mixed acids; and 5) retarded acid systems. The use of each solution is dependent on specific conditions relative to the underground geology, including temperature and rock formation. These solutions are the main components of the acid treatment and act to dissolve the formation to open pore spaces. Postflush fluids are used to completely remove prior fluids, remove damage to the formation, and to protect downhole equipment.

With any type of well stimulation, all stimulation fluids must be compatible with the formation and fluids used during drilling. Consequently, the characteristics of fluids used for well stimulation vary considerably from formation-to-formation, and often vary from well-to-well within the same formation. To achieve the required compatibility, chemical additives may need to be combined with the stimulation fluid. Additives include, but are not limited to, alkalines, surfactants, demulsifiers, defoamers, corrosion and scale inhibitors, and paraffin and asphaltine inhibitors. Each of these may be used in combination with hydraulic fracturing or acidizing in order to address certain formation or well characteristics. Exhibit 1 presents many of the components used during fracturing and acidizing.

Exhibit 1

Components of the Well Stimulation Processes

Activity	Components
Hydraulic Fracturing	Fluids: Water (fresh or brine) Liquid Carbon Dioxide Liquid Nitrogen Nitroglycerine Crude Oil Kerosene Foam Invert Emulsions
	Additives: Proppants (silica) Gels Polymers Friction Reducers Surfactants Biocides Defoamers Fluid loss Lost circulation
Acidizing	Preflush Solution: Ammonium chloride pH buffers Corrosion inhibitors Gels, Viscosifiers Surfactants Diverters Polymers Friction reducers Weighting agents Bridging agents
	Acid Solution: Mineral acids (Hydrochloric, Hydrofluoric) Organic acids (Formic, Acetic) Powdered acids (Sulfamic, Chloroacetic) Acid mixtures Retarded acid systems
	Postflush Solution: Ammonium chloride Corrosion inhibitors Weighting agents Viscosifiers Gels, gel breakers Surfactant

Source: EPA, 1996.

4.0 Wastes Associated with Hydraulic Fracturing and Acidizing

Generally, the vast majority of liquid wastes from fracturing or acidizing will be pumped out of the well, in combination with produced water and other wastes, after the stimulation process is complete. These wastes range from the base fluids (in combination with the additives) and formation fluids to solids that are circulated out of the well and brought back to the surface.

Exhibit 2 shows, on average, for selected States and the U.S. total, the estimated volume of completion/workover fluids generated per well by acid treatments or hydraulic fracturing. These eleven States account for over 80 percent of the nation's completion/workover fluids and number of wells treated by acidizing or hydraulic fracturing.

Exhibit 2

**Waste Stimulation Fluids and Number of Oil and Gas Wells
Treated for Selected States and U.S.
(1985)¹**

State	Workover/ Completion Fluids Generated (Bbl)	Number of Wells Treated by Acidizing or Other Chemicals or by Hydraulic Fracturing	Fluids Generated per Well Treated (Bbl)
Alabama	838	540	2
California	124,385	8,600	14
Colorado	19,381	3,660	5
Kansas	119,325	5,540	22
Louisiana	45,308	16,480	3
New Mexico	327,788	5,780	57
North Dakota	318,419	1,640	194
Oklahoma	1,824,092	19,300	95
Texas	1,931,041	47,080	41
Utah	5,845	1,560	4
Wyoming	76,137	4,820	16
Total	4,792,559	115,000	—
Total U.S.	5,656,082	139,140	41

¹ Excludes on-site injection.

Source: EPA, 1996.

Very little information on the characteristics of completion and workover wastes is currently available. EPA previously found only fourteen fluid samples from over 100,000 acidizing and fracturing jobs performed between 1977 through 1992.⁴ Most of the samples were obtained from offshore wells. Based on the samples obtained, recovered acid fluids had neutral pH values and oil, grease, and metal concentrations were uniformly lower in the recovered fluids than in their pretreatment state. While organic compounds are generally found in the additives used in completion and work over fluids, the fluids were not sampled for their presence.

5.0 Well Numbers and Distributions

Almost all producing oil and gas wells in the U.S. experience some type of well stimulation treatment at some point during their productive life. Over time, the productivity of wells will tend to diminish as scale accumulates in the wellbore, causing the porosity of the formation near the wellbore to decrease. These wells are typically stimulated in order to enhance their production potential. This is somewhat in contrast to most wells in unconventional gas formations, which generally require hydraulic fracturing when drilled to make them

⁴ EPA's report suggests that States that require waste analyses under the UIC Program would likely have additional data.

commercially viable. Those unconventional gas wells also often require additional stimulation treatments later in their life. The information discussed in more detail below indicates that:

- * The number of well stimulation treatments per year is increasing and this rate of increase is expected to continue;
- * The number of wells stimulated annually significantly exceeds the number drilled;
- * Fracturing activities occur in many hydrocarbon basins throughout the U.S.; and
- * Significant gas resources exist within unconventional settings that require hydraulic fracturing to be economic.

5.1 Estimated Number of Stimulated Wells

Exhibit 3 shows the number and fraction of producing wells hydraulically fractured and acidized for every fifth year between 1967 and 1992. As shown, the number of wells undergoing these operations has been increasing over time, with the overall percentage of wells treated also increasing. In 1992 alone, over 140,000 wells were hydraulically fractured or acidized, which is significantly greater than the number of new wells drilled.

Exhibit 3

Oil and Gas Wells Treated by Hydraulic Fracturing, Acidizing and Other Chemical Treatments, 1967-1992

Year	Number of Producing Wells	Exploration and Development Wells	Hydraulic Fracturing		Acidizing and other Chemical Treatments		Total Treatments	
			Number Treated	Percent Treated	Number Treated	Percent Treated	Number Treated	Percent Treated
1967	667,610	33,818	27,500	4.1	27,000	4.0	54,500	8.2
1972	629,601	29,420	24,000	3.8	64,700	10.3	887,800	14.1
1977	655,052	47,308	30,000	4.6	70,800	10.8	100,800	15.4
1982	785,910	84,729	84,100	10.7	101,600	12.9	185,700	23.6
1987	864,919	35,538	49,000	5.7	59,100	6.8	108,100	12.5
1992	865,574	24,065	71,200	8.2	71,300	8.2	142,500	16.5

Source: EPA, 1996; API, 1995.

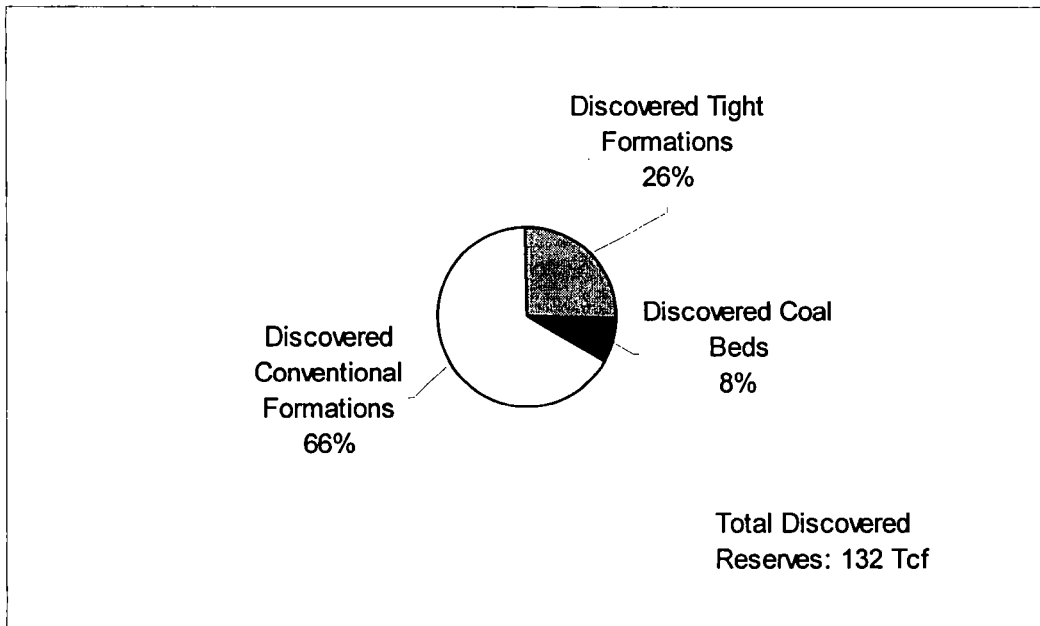
5.2 Contribution of Unconventional Gas to Domestic Supplies

Most forecasters predict that gas production in the U.S. is likely to increase considerably in the next decade, primarily in response to increasing concerns about emissions from alternative fuels. As production matures in the more conventional fields, an increasing amount of domestic production will occur from unconventional sources. As reserves from unconventional sources become increasingly accessed, an increasing number of wells drilled to access these sources can be expected to be hydraulically fractured and acidized. These wells, given their characteristics, will be predominantly completed using hydraulic fracturing techniques. Approximately 3.6 Tcf per year of gas is currently produced from unconventional gas resource settings, which represents about 20 percent of U.S. production. Over 30 percent of currently proved gas reserves in the U.S. exist in unconventional settings. However, of the estimated gas resources in the U.S. that remain to be discovered (and have not yet been proved) nearly 60 percent are estimated to exist in unconventional settings. It is also important to note that since 1990, nearly two-thirds of all new gas wells drilled in the U.S. have been wells targeted at unconventional gas resources.

Exhibits 4 and 5 show the current distribution of the domestic gas resource potential by category of resource and the projected distribution of resource recovery by reserve type, respectively. As shown, most discovered reserves are associated with conventional geology and would not necessarily require the use of stimulation techniques, but the majority of undiscovered, future reserves are associated with unconventional geologies and would most likely depend of these techniques to make them commercially viable.

Exhibit 4

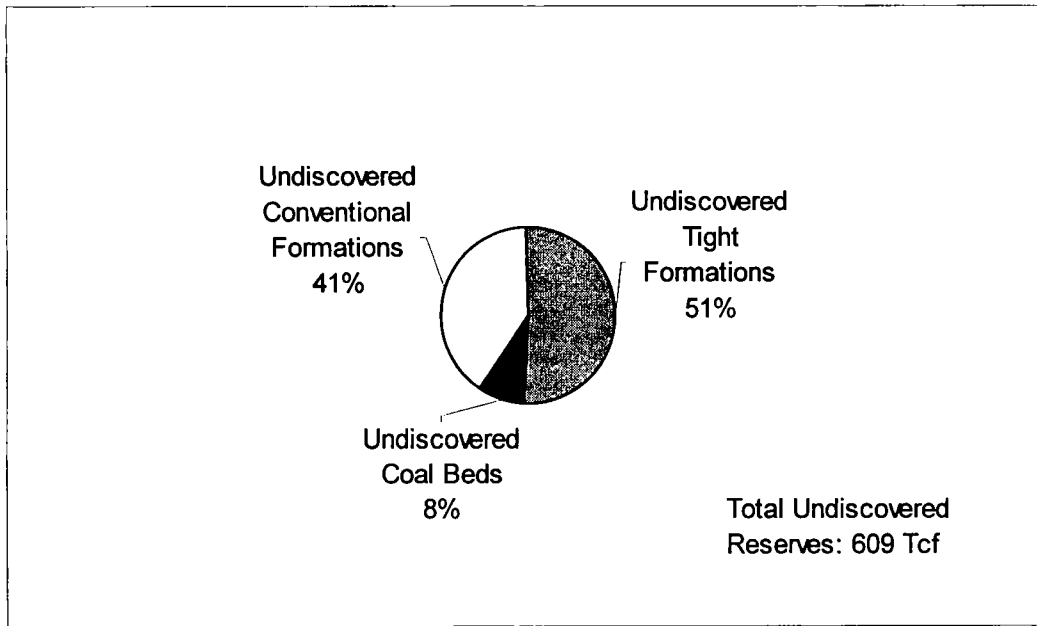
Discovered Gas Reserves of the United States



Source: USGS, 1995.

Exhibit 5

Undiscovered Gas Reserves of the United States



Source: GRI, 1997.

Exhibits 6 and 7 show the distribution of the major coal bed and tight gas basins of the United States in the lower 48 States. The exhibits show that these formations do not occur in one predominate area, but are distributed throughout the country. Exhibits 8 and 9 show the production, proved reserves, and remaining estimated undiscovered resources for each of these regions.

Exhibit 6

Distribution of Gas Resources from Coal Beds of the United States

Exhibit 7

Distribution of Gas Resources from Tight Sand and Devonian-age Shale Formations of the United States

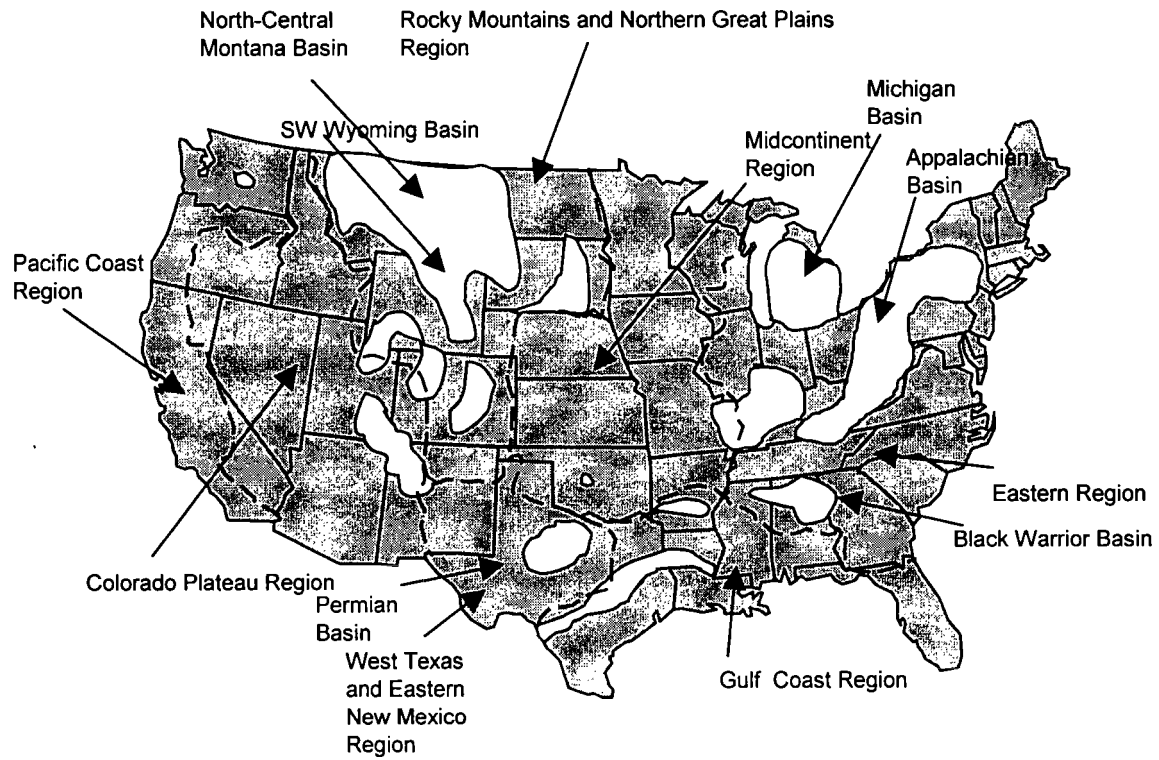


Exhibit 8

Technically Recoverable Gas Resources from Coal Beds of the United States (Tcf)

Region	Basins	1994 Annual Production	1994 Discovered Reserves	Undiscovered Reserves
Pacific Coast	Oregon-Washington Bellingham West Cascade	—	—	0.70
Colorado Plateau	Wind River Wyoming Uinta-Piceance Raton San Juan	0.68	7.41	18.24
Rocky Mountains and Northern Great Plains	Powder River Wind River SW Wyoming Raton	0.04	0.15	7.20
Permian	Permian	—	—	—
Gulf Coast	Mississippi Alabama	0.11	0.98	—

Midcontinent	Arkoma Forest City Cherokee	—	—	5.10
Eastern	Appalachian Illinois Black Warrior Cahaba	0.03	1.54	18.78
Total Coal Beds		0.85	10.07	50.02
Percent of Total Reserves ²		5.5	7.6	8.2

Source: 1995 Assessment of U.S. Oil and Gas Resources, USGS.
1997 Baseline Projection Data Book, GRI.

² total reserves = conventional + unconventional.

Exhibit 9

Technically Recoverable Gas Resources from Tight Sand and Devonian-age Shale Formations of the United States (Tcf)

Region	Basins	1994 Annual Production	1994 Discovered Reserves	Undiscovered Reserves
Pacific Coast	Oregon-Washington	—	—	12.2
Colorado Plateau	Uinta-Piceance Paradox San Juan	0.41	9.55	38.09
Rocky Mountains and Northern Great Plains	North-Central Montana Williston SW Wyoming Denver	0.50	6.53	165.76
Permian	Permian	0.27	2.30	—
Gulf Coast	Western Gulf East Texas	1.03	7.53	8.67
Midcontinent	Oklahoma North Central Michigan	0.23	1.77	—
Eastern	Appalachian Michigan Illinois	0.47	6.41	83.36
Total Tight Formations		2.91	34.09	308.08
Percent of Total Reserves ²		18.8	25.8	50.5

Source: 1995 Assessment of U.S. Oil and Gas Resources, USGS.

7.0 Damage Occurrences

In EPA's 1987 Report to Congress on wastes from oil and gas exploration and production, the Agency described 62 cases of damage to ground or surface water attributable to oil or gas exploration or production operations in 14 states.⁵ One case of contamination of a drinking water well in West Virginia (designated as WV 17 in the Report to Congress) was attributed to hydraulic fracturing of a gas well. In this case, the water well (416 feet deep) and gas well (depth not available) were reported to be less than 1000 feet apart. Use of the drinking water well was reported to be discontinued as a result of the contamination.

The Office of Solid Waste reports that they have not conducted any additional investigations of damage cases attributable to oil and gas well drilling or operation since completion of the Report to Congress.⁶ Initial conversations with personnel in several EPA regional offices indicate that there may be some more recent cases in which fracturing activities may have resulted in ground or surface water contamination. We intend to pursue these leads further as part of discussions next week with selected states concerning their current approach to regulating and overseeing oil and gas well fracturing activities.

8.0 State Regulations

ICF contacted several EPA regional representatives as a first step to identify nine States that appear to be the best candidates for collection of information on how (and if) well stimulation activities are currently regulated and whether ground water contamination has occurred as a result of such activities. Based on readily available in-house information, it appears that States do not regulate fracturing conducted for production purposes; however, it is possible that some States may require notification that a well fracture has occurred as part of its resource conservation program. Several regional EPA representatives also stated that they were aware of a few ground water contamination claims, but it is not clear at this time whether this contamination was the result of well fracturing activity.

⁵ U. S. Environmental Protection Agency (EPA), 1987. *Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, EPA Office of Solid Waste and Emergency Response, EPA/530-SW-88-003.

⁶ Steve Sowders, Office of Solid Waste, personal communication with Mike Godec, ICF, March 1998.

⁷ ICF would expect to contact state personnel responsible for production well regulation first and then personnel responsible for UIC regulation as needed.

Exhibit 10 is a suggested list of nine States for possible future contact.⁷ These States were identified either because they were thought to have at least one potential case of ground water contamination from fracturing or because they are associated with a currently high level of gas production from unconventional settings in the State that would likely require fracturing to be productive. Several of these States, however, do not have primacy for the UIC Program, which may affect EPA's decision to include them on the list of States to contact.

Exhibit 10

Candidate States for Further Information Collection

State	EPA Contact / UIC Contact	Reason
Alabama	Nancy Marsh 404-886-4237 / Richard Ramond 205-349-2852	Reported Well Contamination
Kansas	Kurt Hildebrandt 913-551-7413 / ML Krophage 316-337-6200	High Production
Kentucky *	Nancy Marsh 404-886-4237 / Carol Tarvas 404-562-9743	Reported Well Contamination
Louisiana	Ken Sanborn 918-287-4041 / Jim Welsh 504-342-5500	High Production
Montana	Chuck Williams 313-312-6625 / Jim Boyter 406-441-1140 ext. 233	Reported Well Contamination & High Production
New Mexico	Ken Sanborn 918-287-4041 / Lori Wrotenbery 505-827-7132	High Production
Oklahoma *	Kent Sanborn 918-287-4041 / Mike Battles 405-521-2302	Reported Well Contamination
Texas	Ken Sanborn 918-287-4041 / David Shieck 512-463-6893	High Production
Wyoming	Chuck Williams 313-312-6625 / Don Basko 307-234-7147	High Production

* States without primacy but with UIC Direct Implementation Plans.

⁷ ICF would expect to contact state personnel responsible for production well regulation first and then personnel responsible for UIC regulation as needed.

Statement of

DRAFT#2 -7/20/00; 2:10 PM

**Robert S. Kripowicz
Principal Deputy Assistant Secretary
for Fossil Energy
U.S. Department of Energy
to the
Senate Energy and Natural Resources Committee
July 25, 2000**

Mr. Chairman and Members of the Committee:

By anyone's account, it has been a remarkable quarter century for natural gas in this country.

In the mid-1970s, natural gas was thought to be a declining fuel. Outdated and counter-productive pricing regulations had handcuffed the industry, stifling exploration and production, and conveying the false impression that the Nation's gas supply was on the wane.

Today, the picture is decidedly different. Far from being a dying resource, natural gas is being counted on to fuel much of America's economic expansion for well into the 21st century. The onerous regulations of the 1970s have been replaced by a restructured and highly competitive gas market, and the industry has responded.

In 1992 the National Petroleum Council conducted a major study of the natural gas potential within the United States. The Council, as many Members of the Committee are aware, is an industry advisory panel to the Department. It has some of the top leaders in the oil and gas industry as its members. Its studies are often cited as the definitive view of the industry by those who know the industry the best. The Council's 1992 study concluded that the United States had about 1,300 trillion cubic feet of natural gas resources outside of Alaska.

This past December, the Council issued an update of the 1992 study requested by the Secretary of Energy. The new analysis found that – despite the fact that Americans consumed 124 trillion cubic feet of natural gas since the 1992 study – the estimate of the nation's gas resource has actually *increased*. It now stands at more than 1,466 trillion cubic feet.

Advances in technology have opened new frontiers, and new production tools have led to more gas being extracted from both newly discovered and older fields.

The Council's study boosted confidence in the future of gas supplies, but it also raised cautions. The Council stressed that adequacy in the ground does not automatically translate into adequacy at the burnertip. There will be challenges to overcome.

For one thing, gas demand is growing faster than virtually anyone predicted. When one looks back at the forecasts made by the Council just 8 years ago, even its most robust expectations for growth in gas demand have been exceeded by what has actually occurred.

The U.S. economy is growing faster than anyone expected. Environmental regulations that favor natural gas consumption are more firmly in place than in 1992 and are becoming increasingly stringent.

Power companies are looking at the quickest, lowest capital cost options to install new generating capacity. In fact, more than half of the growth in demand for natural gas over the next 20 years will come from the electric generation market. The Energy Information Administration's *Annual Energy Outlook 2000* projects that of the 1000 new power plants likely to be built in the United States in the next 20 years, 900 of them will likely be fueled by natural gas.

Overall, the use of natural gas in this country could increase by more than a third in the next 20 years. But in the electric power generation industry, demand for natural gas for power generation could increase by as much as 250 percent.

New technologies are clearly spurring the use of more natural gas. Universities and large conference centers – such as Opryland in Nashville and the McCormick Center in Chicago – are now turning to highly efficient combined cooling, heat and power systems fueled by natural gas. The Brookfield Zoo in suburban Chicago now has an onsite natural gas cogeneration system, installed in 1998. A Walgreen's drug store in Chesterton, Indiana, became an energy pacesetter last year when it installed a natural gas "microturbine," about the size of a commercial refrigerator.

In New York's Central Park, the park's only police station is now powered by a natural gas fuel cell. Its installation saved the costs of running a very expensive underground transmission line through the Park.

And lest we overlook some of the traditional uses of natural gas, it is important to point out that natural gas is now the fuel of choice for 70 percent of new single family homes.

The 30 TCF Gas Economy – Not "If" But "When"

All of this points toward extraordinary growth in gas use.

The Energy Information Administration projects that by 2015, annual consumption for natural gas will reach almost 30 trillion cubic feet (tcf) -- up from today's 21 tcf. By 2020, consumption is likely to continue to rise to almost 32 tcf.

The National Petroleum Council forecasts that we could reach the 30 tcf mark sooner, perhaps shortly after the year 2010, and that in two cases, consumption could be as high as 33 tcf by 2015.

The American Gas Foundation published a recent study, conducted by former Deputy Energy

Secretary Bill Martin, that describes a scenario in which gas consumption in 2020 could be 60 percent higher than today – reaching more than 34 tcf. Some forecasters have estimated that if greenhouse gas controls are enacted, demand for natural gas could approach 40 tcf by 2020, nearly doubling today's consumption.

Can the Gas Industry Deliver? A Sense of Cautious Optimism.

These are extraordinary forecasts for a fuel that was virtually given up on in the 1970s. The Energy Department agrees with the National Petroleum Council and others that there is good reason for optimism within the nation's gas industry, but we also agree with the Council that the optimistic projections must be tempered by a sense of caution.

America's gas future is not preordained. The downturn in world oil prices that began in late 1997 and extended into early 1999 dealt a heavy blow to the exploration and production sectors of the U.S. gas industry. Particularly hard hit were the oilfield supply and service contractors and the independent producers who now account for nearly two-thirds of the country's gas supply. Many people are unaware that approximately 16 percent of the Nation's natural gas production is linked directly to the production of crude oil.

But the challenges confronting gas use in this country go beyond short-term price fluctuations. The National Petroleum Council identified more deep seated and longer-range issues that must be addressed.

For example, the Council estimated that the gas industry will require almost \$1.5 *trillion* (1998 dollars) in private sector financing through 2015. More than half – nearly \$781 billion – will be needed for new capital investments to find, produce and transport natural gas.

But the challenges don't end with dollars. To connect the anticipated 15 million new gas consumers in the next 15 years, enough new pipe will have to be fabricated to stretch from the Earth to well past the Moon. More than 255,000 miles of distribution mains and more than 38,000 miles of new transmission lines are likely to be needed in just the next 15 years.

Industry will have to attract the investment capital and human resources to build these pipelines. But government will have to find ways to minimize impediments – including streamlining rights-of-way and permitting.

The Federal Energy Regulatory Commission took a step in that direction last September when it adopted a policy statement that increased the flexibility of the provisions it uses to evaluate pipeline projects. The policy statement confirmed that the Commission will begin its environmental review at the time an application is filed. Environmental and economic reviews will continue to proceed concurrently.

This is a step in the right direction, but it doesn't address the lengthy time it takes to comply with the National Environmental Policy Act and other permitting procedures. We're looking into

ways to expedite that process and to provide the Commission with notification of permit decisions and other information more rapidly. That, in turn, will help streamline the Commission's deliberative process.

There are other challenges confronting the gas industry. To meet future demand projections, the National Petroleum Council estimated that the number of wells drilled each year – including those that come up dry – will have to double from 24,000 in 1998 to more than 48,000 by 2015. The number of drill rigs will have to increase by 60 percent.

Thousands of new workers will be needed – in an industry that has lost more than 400,000 jobs in exploration, production and other “upstream” skills since the early 1980s. Largely as a result of the employment downturn, there has been a significant drop off in college enrollment in petroleum-related disciplines. That trend must be turned around.

The most daunting challenge, however, may not be how or who will drill for tomorrow's natural gas, but where. Much of the nation's gas resource resides on federal lands or in federal waters. Two of the most promising regions for future gas production are the Rocky Mountains and the Gulf of Mexico. Yet, the National Petroleum Council pointed out in its December 1999 report that an estimated 40 percent – or 137 TCF – of potential gas resource in the Rockies is on federal land that is either closed to exploration or is open under restrictive provisions. Another 76 TCF of resources are estimated, according to the Council, for restricted areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific.

The Council recommended that an Interagency Working Group be established at the White House to deal specifically with natural gas issues, including access. That group has not yet been formed, but in the interim, we have begun several efforts that could help resolve issues that have restricted access. For example:

- * DOE, the Bureau of Land Management (BLM), the Forest Service, the Environmental Protection Agency, the Fish and Wildlife Service, the National Park Service, and the Bureau of Indian Affairs have joined to develop ways to streamline the environmental review processes that must be conducted before federal lands in the Rocky Mountain region can be leased and again, before actual drilling can occur.
- * We have joined with the Wyoming State Geological Survey, the Wyoming Oil and Gas Conservation Commission, and several federal agencies to develop a science-based regional assessment of oil and gas resources throughout the State. This assessment, which crosses over ownership boundaries, will be available for use in future resource development.
- * We're working jointly with BLM to develop technologies that are particularly applicable to oil and gas production on federal lands. In the past, this has included air quality monitoring in Wyoming and land remediation in Oklahoma. This year, we will be conducting coalbed methane research in Colorado and Wyoming, analyzing compressor

noise on wildlife in New Mexico, studying the effects of oil and gas activities on wildlife in Wyoming, and developing a model for predicting cultural resources in Nevada.

The Promise – and Necessity – of New Technology

Advanced technology – from both a production and an environmental standpoint – will be one of the most critical factors, perhaps *the* most critical factor, in determining whether natural gas achieves its full potential.

As the Energy Information Administration points out, rapid technology development could translate into as much as 2.7 trillion cubic feet of additional gas produced domestically in the U.S. by 2015 compared to a slow rate of technology development (or 1.25 trillion cubic feet of additional gas compared to the “business as usual” reference case). The price impact could be even more dramatic – the wellhead price of natural gas could be as much as 44 percent cheaper by 2015 if the pace of technology development is rapid compared to the slow technology case (or nearly 20 percent cheaper compared to the reference case).

One of the points stressed by the National Petroleum Council was the remarkable progress in technology that was not fully anticipated in 1992. Three-dimensional seismic technology now allows producers to spot small hydrocarbon accumulations that would have been bypassed just a few years ago.

New time-lapse reservoir modeling – or as it is commonly called, 4-D seismic – coupled with other imaging technology now allows producers to “see” reservoir events, such as a gas cap enlarging as oil is produced. In the future, real-time reservoir modeling will use these techniques to allow drilling and field decisions to be made more rapidly, on-the-spot, to maximize production.

If gas is to achieve its full potential, tomorrow’s gas producers will have to drill deeper, faster, and smarter. The Department of Energy helped pioneer the polycrystalline diamond drill bit, the measurement-while drilling technology, the “thru-casing” logging system, and several other innovations that have allowed the hydrocarbon industry to probe deeper into more hostile environments searching for natural gas.

But if tomorrow’s producers are to keep pace with the steadily growing demand for natural gas, even more impressive innovations will be needed. The drilling systems of the future will likely need to be “smart systems,” incorporating rugged integrated circuitry to monitor conditions at the drill bit, analyze for hydrocarbons in “real time,” and steer the bit through rock that is deeper and denser than has ever been encountered before.

Recently, for example, new gas research projects were selected to determine the feasibility of using a laser to drill natural gas wells, to improve a novel “down-hole hammer” which uses the power of the drilling fluid to help drive a drill bit into a gas-bearing formation, and to develop an ultra-lightweight cement that could help lower the costs of completing natural gas wells.

A little over a year ago in southwestern Wyoming, in a project we helped cosponsor, Union Pacific Resources drilled a 17,000 foot deep well with a 1,700-foot horizontal section – one of the longest horizontal wells drilled into the tight sand formations of the Rocky Mountains. Production was well above expectations, and that has led to additional privately funded horizontal wells in the same Green River formation.

This project is especially important because onshore production from nonconventional formations – like the Rocky Mountain tight sands – is likely to increase significantly over the next 10 years. By 2015, as much as a quarter of the natural gas we produce in the United States could be coming from nonconventional gas reservoirs.

The offshore Gulf of Mexico is another prime area for increased gas production. New technology now allows producers access to gas supplies in ocean waters more than a mile deep, and exploration wells are now being completed in over 8,000 feet of water.

And in the even longer term, there may be the potential for tapping the enormous energy potential of methane hydrates beneath the ocean floors or the Arctic tundra – but that may require technologies we can only imagine today.

The Potential for “White Crude” from Remote Gas Sources

In Alaska’s far North Slope, there are vast natural gas resources that remain unmarketable because the gas is too remote from the marketplace and there is currently no cost-effective means for transporting the fuel in gaseous form.

Natural gas, however, can be used as a source of chemical “building blocks” to synthesize liquid fuels. In liquid form – or as it has been called, “white crude” – the natural gas from the North Slope could keep the TransAlaska Pipeline System (TAPS) flowing well beyond its currently projected economic lifetime and supply needed liquid fuels that could help the U.S. reduce its dependence on imported crude oil. In fact, by keeping TAPS open for both new gaseous-based liquid fuels and additional oil production, total North Slope oil production might be enhanced by almost 1 billion barrels.

Two years of research in our gas-to-liquids program is now reaching the point where several classes of ceramic membranes and seal materials have been proven suitable for chemically converting natural gas into gases that could be recombined into liquid fuels. Cost savings of up to 30 percent over conventional gas separation processes appears to be within reach. In FY 2001, a prototype membrane unit capable of processing 24,000 cubic feet per day of syngas (equivalent to 0.75 barrels per day) will be built and tested. Design and engineering will be started on an even larger, 500,000 cubic-foot-per-day unit (equivalent to 15 barrels per day).

A New Initiative in Infrastructure

Tomorrow’s research partnerships must also extend beyond just the gas field itself. For the first

time, in our fiscal year 2001 budget, the Energy Department included a funding request for significant research into the infrastructure of future gas delivery.

Pipelines and Local Distribution Companies will continue to rely on the development of advanced technology for reducing operation and maintenance costs. There will need to be research to reduce stress corrosion and cracking in gas transmission and distribution lines. There will be a need for smarter, automated, inside-the-pipe inspection systems that can not only sense weak points but repair them. There will be a need to develop portable optical imaging technology to detect natural gas leaks in pipelines, storage and processing facilities. There will be a need for new technologies that can expand storage capacity near market centers to meet peak demand periods.

The Strategic Center for Natural Gas

But it's not just a question of the dollars we are spending – but whether we are spending them in the most efficient manner to address the right issues.

Three different parts of the Department are responsible for spending the \$200-plus million dollars we direct annually at natural gas-related research and development. But until recently, there was no single focal point to coordinate those efforts or to determine if there were gaps in the Energy Department's natural gas portfolio.

I'm pleased to report that this has changed. Last December, Secretary Richardson announced his intent to create a new Strategic Center for Natural Gas as part of our new National Energy Technology Laboratory in Morgantown, West Virginia, and Pittsburgh, Pennsylvania. In March, the Center became operational.

Its mission is to work with the nation's gas producers and users, to set the course for future gas policies and programs, and to help ensure that this country has the technological capability to meet tomorrow's demands for natural gas.

The Center will perform four key functions:

- * ***Spearhead annual DOE-wide gas RD&D planning and program assessment.*** The Gas Center will work closely with other DOE offices¹ to develop an integrated Natural Gas Strategic Plan that will establish high-level budget and policy priorities for all natural gas programs within the Department. The Center will also provide support to individual program offices for detailed natural gas road-mapping activities in each market sector to provide a consistency of approach. In addition, the Center will identify gas in the

¹ These offices will include the Offices of Fossil Energy (FE), Energy Efficiency and Renewable Energy (EE), Science, Policy, International Affairs, and the Energy Information Administration.

Department's natural gas programs and work closely with other policy and planning activities to establish appropriate government-industry partnerships to fill priority research and analytical needs.

- * *Provide science and technology advances through the Laboratory's on-site programs.* Through in-house research at the National Energy Technology Laboratory, the Center will provide cutting-edge science and technology for the clean, efficient production and use of natural gas. For example, the Gas Energy Systems Dynamics Focus Area is developing the basic science to understand the unsteady processes of natural gas combustion and conversion in advanced energy technologies, such as fuel cells, combustion turbines, and coupled turbine-fuel cell systems. Other onsite research areas to be emphasized by the Gas Center include computational analyses of advanced turbine and fuel cell components, methane hydrates, and the geologic sequestration of greenhouse gases.
- * *Shape, fund, and manage extramural research and development.* A major activity of the Gas Center will be to manage gas-related contracts and grants with U.S. industry, universities, and other national laboratories. The Gas Center will form an alliance with the National Renewable Energy Laboratory (NREL) to provide for the complementary implementation of a complete portfolio of gas and other energy technologies.²
- * *Conduct studies to support policy development.* The Gas Center will develop and use analytical tools to assess natural gas policy options. This will be done in conjunction with DOE's headquarters program offices, the Office of Policy, and the Energy Information Administration.

Conclusion

It took us a quarter century to realize the true extent of the domestic energy treasure we have beneath us in the form of natural gas. Now, we must understand and take on the challenges if the full value of that treasure is to be realized over the next quarter century.

Advances in technology do not happen overnight – nor do they happen in a vacuum. Both industry and government are going to have to work hard to keep the technology moving forward. The growing dominance of independent producers in this country, many already strapped for cash, will create new challenges for R&D investments. The phase out of the R&D tariffs that supported the technology efforts of the Gas Research Institute will be another important factor.

² On July 14, 2000, 18 representatives of the natural gas and renewable energy industries signed a “statement of principles” to develop a new alliance to promote a common agenda for the development of natural gas and renewable energy technologies.

If gas is to live up to its expectations, the need to fill these funding gaps – the need to leverage funding in research partnerships, including partnerships with the Federal government – will become increasingly important.

As the National Petroleum Council said in its December, 1999, report:

“...the resource base exists to support the indicated levels of future demand and adequate gas supplies can potentially be produced to meet that market. The additional supply required can be brought to market at competitive prices through an expanded network of pipeline, storage, and distribution facilities. However, the Council recognizes that meeting the significant challenges that accompany such vigorous market growth will require strenuous effort by the industry and substantial support on key issues by the government.”

This completes my prepared statement. I will be pleased to answer any questions Committee members may have.

A Quiet Energy Crisis

Motorists and politicians alike are worrying loudly about the highly visible price of gasoline. But that's not the only energy price that is up. Natural gas prices have doubled since the first of the year, which is very significant for a commodity that supplies a quarter of our total energy needs. At the same time, electricity prices are going up this summer in many parts of the country, and the possibility of brownouts is a worry in some regions. Altogether, an unusually tight market balance stretches across the energy supply systems. This is likely to lead to continued volatility in energy prices for the rest of the year—and generate increasing political heat as November approaches.

In contrast to oil, the high prices of natural gas and power are driven by home-grown market forces—stagnant supply in the face of strong demand. But they also point to something new—an increasingly complex and intricate interconnection between the electric power and natural gas industries that underpins economic growth.

Electricity is becoming ever more central to our economy as the digital economy depends upon a very high quality electricity supply system. But electricity, in turn, will more and more depend upon natural gas. Indeed, the United States is making a major bet on future gas supplies—largely without realizing it. A great deal of new electric power generating capacity is currently proposed—almost 250,000 megawatts—equivalent to a third of existing capacity. Just 15 percent of our current electric generating capacity is fired by natural gas. But an extraordinary 95 percent of the new proposed generating capacity is gas-fired! Not so many years ago, regulation precluded burning natural gas in new power plants. No more.

The reasons for the overwhelming dominance of natural gas in this round of power plant additions are several: dramatic advances in the efficiency of new gas turbines; low capital costs; cheaper, cookie-cutter design; and environmental attractiveness. What has not been anticipated, however, is the surge in natural gas prices. Deregulation of natural gas prices in the late 1970s turned into a massive political battle. The political heat dissipated with experience. For the result of deregulation has been a well-supplied market that has resulted overall in lower prices for consumers.

But the past few years have proved difficult for the industry. Equity investors, who might have helped fund new gas development, have instead turned—at least until recently—to Internet stocks to satisfy their taste for risk and reward. The oil price collapse of 1998-99 dramatically reduced the cash flows for companies that explore for gas as well as oil. Instead of new geological plays, these companies concentrated on cutting costs and preserving cash. All this has meant reduced gas supply development activity. The result: Gas production capability in the United States has fallen by nearly 7 percent since 1997. The challenge for the industry is to reverse the decline in supply and get on a path to meet rapidly accelerating demand from the power industry. The price tag will not be cheap. We estimate that this will require an investment of more than \$500 billion over the next decade—nearly double the level of the 1990s.

Only now after prices have doubled to well over \$4 per million British thermal units in the Gulf Coast are investors beginning to show renewed interest in natural gas. But the long-term nature of supply development means there is no easy short-term solution to the price pressure. Storage inventories, which provide the buffer and flexibility when demand surges, are low. Industrial customers are already feeling the effects of 40 percent to 70 percent increases in their total gas bill. During the summer months, when usage is low, most residential customers will be oblivious to the price changes. But a delayed realization will certainly come next winter, when higher prices trip in for the 60 million homeowners who use gas for heating. In due course, the cost for gas-fired electric power will also reflect the higher prices.

Despite the current supply challenge, the resource base in North America remains vast. The increased revenue will spur new investment in natural gas supply development. We anticipate that revenue for gas producers in North America will increase by more than \$25 billion this year—from about \$40 billion to more than \$65 billion—with much of this available for investment. While natural gas may still be viewed as part of the “old” economy, perspective is helpful. This incremental \$25 billion is more than the total revenue of Cisco, Amazon, Nextel and eBay combined. And unlike in the past, when such a “boom” in commodity prices was usually met by a bust shortly thereafter, natural gas prices are likely to remain strong for the next three to five years.

Already there are signs of major new supply development programs being considered—including new development in the ultra-deep waters of the Gulf of Mexico, a major increase in liquefied natural gas imports, and the development of the extensive reserves in the United States and Canadian arctic. Unfortunately, few of these resources will have a major effect on supply until 2004 or beyond. In the interim, it will be up to exploration and production in areas such as the Rocky Mountains or Western Canada to stave off a more serious gas supply shortfall until the frontier supplies are developed.

Gasoline prices are now said to be the number one political issue in the country. Before this election season is over, natural gas prices are likely to become part of the political process. There will be calls for intervention and renewed regulation. That will have an effect just the opposite from what is intended. For such intervention directly into the markets—such as price caps—or even talk of such intervention, will scare investors away from the energy sector—and push off further the timing of a meaningful supply response. What is really needed right now is the recognition that major new natural gas development is not opposed to but rather essential to meet overall environmental objectives—and that such development is urgent in order to keep the new economy humming.

Daniel Yergin is chairman of Cambridge Energy Research Associates. Thomas Robinson is managing director and lead author of the new study: "On the Frontier: the Future of North American Natural Gas Supply."

714-1287

of a 1994 anti-crime package increasing the application of the federal death penalty, that forbids the killing of the gravid.

This is apparently not a problem that has ever come up in the real world—among other reasons, because shuffling a woman from conviction to the date of execution takes at least 12 times longer than making a baby. Even so, Gore was able to flub the question, telling Russert that he wasn't familiar with the law and was going to have to think about it. No doubt he smelled a variant of the logical trap that opponents of abortion rights and the death penalty like to spring on those who support one but oppose the other.

Gore is one of the lucky pols who support both abortion rights and the death penalty, and was understandably loath to risk his perfect consistency.

By the next day, happily, Gore figured out that this was a question so hypothetical as to evade moral weight of any kind, and he held a news conference to declare that he firmly opposed snuffing a pregnant woman until after the Blessed Event.

Bush jumped on the opening Gore had created, stagily announcing his dismay that Gore should have had to think about such an obviously simple question. (He declared himself "surprised, frankly" at Gore's confusion. Don't you love the faux gravity of that "frankly"?) Bush himself, who calmly presides over the executions of folks afflicted with lawyers who were sleepy or drunk at trial, specializes in not having to think about the death penalty. He is very definitely opposed to killing women until after they have given birth, he told us. "No matter what your position is on abortion or on the death penalty, you

This has to be scored as a dumber answer than Bush's. Right to choose? Choose *what*? Whether to carry her child to term, or to have an abortion that will hasten her execution date, or to make the state carry out an execution that will also take the life of the fetus (an option that is apparently forbidden by federal law)? Now there's a right worth going to the barricades for.

It would probably be too much to expect either candidate to say the truth: *Geez, Tim, that's a pointless little question. That law is just a bit of pandering Congress did, to look less bloodthirsty; this has never come up and it never will, so let's talk about something important.*

The entire conversation resembles nothing so much as a late-night bull session between a circle of college sophomores. The candidates' willingness to gallop off after these abstractions would be funny, if it weren't such a perfect distillation of the cant and nervousness that male pols bring to the whole spectrum of issues affecting reproductive rights, and especially of the way the presidential campaign has avoided the issue of the death penalty.

Outside the presidential debate, the fairness and efficacy of the penalty itself have been under greater fire than at any time since the Supreme Court reinstated capital punishment in 1976. And Bush's zealous administration of the penalty in Texas raises real questions about his vision of the law. The crucible of presidential politics would be the ideal place to debate this core issue of American justice. But neither candidate entertains any doubts about it, so we discuss the Madonna Exemption instead.

Next week: If a tree falls in the forest, does it make any noise?

*Richard C. Breeden, Roderick M. Hills,
David S. Ruder and Harold M. Williams*

Accounting for Conflicts

In recent weeks, U.S. Securities and Exchange Commission Chairman Arthur Levitt has spoken on the independence of the U.S. accounting profession, an issue that each of us grappled with when we were chairmen. And last month the commission proposed a rule-making initiative on how best to deal with the conflicts created by the profession's ever-expanding menu of (nonaudit) services offered to public company audit clients.

This initiative is timely and necessary—not just for investor confidence but also to preserve the long-term role of the accounting profession as the guardian of objective and independent financial reporting.

In recent years, the accounting profession has undergone enormous change. Firms once dedicated primarily to offering auditing services now also operate significantly in the realm of investment banking, mergers and acquisitions, financial planning, executive recruitment and technology consulting. Accounting firms also are entering into "strategic alliances" with software, hardware, e-commerce and other companies. They are even setting up venture capital funds—hoping to get their piece of the e-commerce pie.

The problem is that offering nonaudit services to an audit client risks confusing a desire to foster commercial relationships with the public responsibility to be impartial and unbiased.

The appropriateness of providing consulting services to an audit client has long been a point of debate. Two decades ago, a congressional report stated that accounting firms "have seriously impaired their independence by becoming involved in the business affairs of their corporate clients."

During our tenures, we all concluded that auditors were successfully remaining independent, but each of us worried about growing commercial relationships with audit clients. Those relationships, subsequently, have continued to grow—as has consolidation among the largest firms.

Today, despite our general confidence in the profession, we believe that the time has come to chart a surer path to

preserving the all-important principle of auditor independence from commercial client relationships.

As every public accountant knows, it's not enough that the financial statements be accurate. The public must perceive them as being accurate. Nothing would fortify public confidence in the accounting profession more than a strong, unequivocal and tangible reaffirmation that the audit function is at the heart of an accountant's work and not just adjunct to a consulting arrangement.

The stakes and pressures behind making the "tough call" on an accounting judgment have always been high. Accounting is not an exact science. It necessarily involves personal judgment. That judgment—to be worthy of the public's confidence—depends on the professionalism and complete objectivity of auditors.

Today, the demand for a company to meet Wall Street's quarterly earnings expectations is relentless. When missing an earnings target by a penny can erase millions, if not billions, of dollars in market capitalization, there's a real temptation for corporate management to lean on the auditors.

Now, consider the audit partner whose firm has significant consulting revenue from the audit client. That partner may be considering not just the quality of the audit engagement but also the far more lucrative consulting contract. The auditor placed between the interest of the public and management may be perceived to lack the objectivity necessary for unbiased financial reporting.

Some will say that action now is premature or unwarranted. They argue that there's no harm unless you can directly tie a firm's nonaudit services to a failed audit. But this claim belies the environment in which many tough business decisions are made. It is rarely the black-and-white issues that an auditor faces. The danger lies in the gray area—where the pressure to bend to client interests is subtle, but no less deleterious.

The writers have all served as chairman of the U.S. Securities and Exchange Commission.

The Washington Post

FRIDAY, JULY 21, 2000

(GAS)

(4) + \$1m

"A New Climate For Reliability"

(1)

Overall Energy System Optimization, Reliability & Emissions Reductions

\$ 8 million

- Optimization of energy distribution systems
- Natural gas cooling (Offset summer electric peak demand while gas distribution system is underutilized.)
- Distributed generation
 - Engines: microturbines, reciprocating engines
 - Enabling technologies: systems interconnection, dispatch, safety, reliability
- Reduction in methane vented or leaked during production, transmission, distribution or utilization (Efficient delivery enhances availability and safety.)

at \$2 need \$2 (2)
e.g. microturbines \$2.5 now need + \$2.5
at \$0, want \$.5
(3)

Enhanced Energy Efficiency

\$ 10 million

- Industrial process efficiency improvements
 - Superboilers, process heating, glass melting
- Combined Heat & Power and Cooling/CHP
 - Waste heat utilization and system optimization research
 - CCHP design tools
- Fuel cells for building and industry applications
- Fuel cell / turbine hybrids

Fuel Substitution

\$ 12 million

- High efficiency gas prime movers
- Increased natural gas supply (Necessary the permit significantly greater use of natural gas under optimized energy delivery scenario.)
- Expanded transmission & distribution infrastructure (Same as above.)

Total

\$ 30 million

“A New Climate For Reliability”

	Energy Systems Optimization, Reliability and Emissions Reductions	Enhanced Energy Efficiency	Fuel Substitution	Greenhouse Gas Reduction
<u>TECHNOLOGY</u>				
Optimization of Energy Distribution Systems	✓	✓	✓	✓
Natural Gas Cooling	✓		✓	✓
Distributed Generation	✓		✓	✓
Reduction in Methane Vented or Leaked	✓	✓		✓
Industrial Process Efficiency	✓	✓	✓	✓
Combined Heat & Power and CCHP	✓	✓	✓	✓
Fuel Cells for Buildings and Industry	✓	✓	✓	✓
Fuel cell / Turbine Hybrids	✓	✓	✓	✓
High Efficiency Gas Prime Movers	✓	✓	✓	✓
Increased Natural Gas Supply	✓		✓	✓
Expanded Transmission & Distribution Infrastructure	✓		✓	✓



DAVID N. PARKER
President and CEO

February 17, 2000

Mr. Roger Ballentine
Chairman
White House Climate Change Task Force
734 Jackson Place, NW
Washington, DC 20503

Dear Mr. Ballentine

I am pleased to enclose the American Gas Foundation's "Fueling the Future: Natural Gas and New Technologies for a Cleaner 21st Century," a comprehensive forecast of significant growth potential for natural gas.

While many contemporary studies continue to focus only on the use of natural gas for central station electricity generation, this study shows that the direct use of natural gas in residential, commercial and industrial applications offers the prospect of a more efficient economy. It outlines how the increased use of natural gas could help the nation meet its environmental, economic and national security goals.

The American Gas Association will release the study publicly on February 16 in an interactive video press conference in New York City and Houston.

Among the study's key findings:

- Estimates of a 30 Tcf market may be too low. "Fueling the Future" sees potential for natural gas demand to jump by nearly 60 percent in the next 20 years--to a level of 35 quads in 2020.
- Technological advances in exploration, production, transmission and distribution will enable the industry to meet this lofty target while maintaining competitive prices.
- The forecast is driven by a number of "new" technologies and applications, from residential fuel cells and fireplaces, to commercial combined heat and power and high tech industrial applications.

For additional information on the American Gas Foundation study, please contact Darrell Henry at 202-824-7219.

Sincerely,

A handwritten signature in black ink that reads "David N. Parker".

Dave N. Parker

American Gas Foundation

400 N. Capitol St., NW
Washington, DC 20001
202-824-7000
www.fuelingthefuture.org

“Fueling the Future: Natural Gas & New Technologies For a Cleaner 21st Century”

Key Findings

- The study shows new and existing technologies will help to increase consumption of natural gas by almost 60 percent by 2020 and consumption patterns will change dramatically.
 - Natural gas is the cleanest, most efficient fossil fuel. Increased use of natural gas could help the nation meet its environmental, economic and national security goals.
 - The benefits of increased use of natural gas to the nation will be tremendous.
-

More than benefits — the role of natural gas should grow

- Using more natural gas can help ease a number of environmental concerns — greenhouse gas emissions, acid rain, smog, solid waste and water pollution. In fact, CO₂ emissions could be reduced by 930 million tons per year.
- Greater reliance on natural gas can have profound energy security benefits and reduce oil consumption by about 2.6 million barrels per day. Virtually all of the gas supply needed to meet the projected consumption level can come from a secure North American supply base.
- Natural gas is a highly efficient use of energy. By substituting gas for oil, coal and electricity, total US energy consumption can be reduced by 6 percent (approximately 7 quads) in 2020.
- The US natural gas resource base is vast and diverse. Technological advances in exploration and production can increase domestic gas production.

New technologies will transform the way consumers view and use natural gas

- “Fueling the Future” shows dramatically different consumption patterns for natural gas in the future — with more gas being used in residential, commercial and industrial sectors and less in electricity generating plants.
- Innovative gas-fueled technologies — especially cooking and distributed generation — are expected to account for a large portion of the increase in gas consumption.

Consumers at home with natural gas

- Fifty-five percent of all U.S. homes have natural gas service. Consumers will continue to favor natural gas, and there is significant potential for conversion of other household applications.

Industry fueled by natural gas

- Natural gas is the primary energy source of our nation’s factories, accounting for nearly 40 percent of the energy used in the industrial sector. The natural gas system is extremely efficient and offers businesses substantial benefits in terms of productivity, reliability, and cost-savings.
- A highly efficient and reliable natural gas delivery system is in place, which consumers, small and large, can tap easily with technologies such as fuel cells, microturbines and advanced gas heating/cooling equipment.

Natural gas vehicle market revs up

- Nearly 80,000 natural gas vehicles (NGVs) are being driven in the United States today. The amount of natural gas used to fuel vehicles is forecast to reach 1.5 quads by 2020. Using natural gas in place of gasoline and diesel fuel greatly lowers the vehicular emissions that pollute the air.

American Gas Foundation

400 N. Capitol St., NW
Washington, DC 20001
202-824-7000
www.fuelingthefuture.org

What Others Are Saying ...

About Natural Gas

"Kroger strongly believes that natural gas is the choice fuel for the future. Combined with emerging technologies, such as distributed generation, natural gas competes and compares very favorably with electricity. Plus, with competitive gas markets largely in place nationwide and the electricity industry struggling with deregulation, we find it easier and more convenient to purchase and use natural gas. Clean – safe – inexpensive – that's natural gas...and that's good for Kroger and its customers nationwide."

*Dennis George, Energy Manager, The Kroger Company
Media inquiries, 513-762-4443*

"For quality performance and reduced maintenance and operating costs, we use natural gas for all our energy needs. Of our 414 stores nationwide, there's just one that doesn't rely on natural gas for its major energy needs. We use gas for our cooking equipment, including fryers, as well as gas steamers and kettle. We also use natural gas for heating and water heating because of cost and, more importantly, reliability."

*Gary Lees
Regional Facilities Manager
BOB EVANS FARM*

About "Fueling the Future"

"Long-term trends in ever-increasing energy efficiency have put the United States at the threshold of a methane economy. With vigorous development and application of technology, the ample natural gas resource base of the nation can be converted to producible reserves at attractive costs and in volumes sufficient to meet a much enlarged demand, thus allowing us to realize the tremendous benefits of a methane economy."

*Dr. William Fisher, 512-471-5600
Professor of geological sciences and interim director of the Bureau of Economic Geology at the University of Texas at Austin; member of the "Fueling the Future" editorial review board*

"The ancient Jewish people told of the gift of manna that rained down from heaven to give them sustenance in the wilderness. Modern man benefits from another substance, partly cosmic in origin and partly stored up in the earth for many millennia through photosynthesis and anaerobic digestion. This modern manna is natural gas. It is of such high quality that, through using advanced technology, it can provide energy services and useful chemicals at a very high efficiency and low environmental costs."

*Dr. John H. Gibbons, 540-253-9843
Karl T. Compton lecturer at Massachusetts Institute of Technology and senior fellow at the National Academy of Engineering; member of the "Fueling the Future" editorial review board*

"Natural gas provides a strong front line defense against global climate change. Natural gas is a vital bridge between today's energy mix, dominated by coal-fired central power stations and gasoline-powered cars, and our energy future, where hydrogen, fuel cells and renewable energy resources will meet our energy needs. Greater use of natural gas, and better total energy efficiency, can reduce greenhouse gas emissions over the next few decades and buy the time still needed for new energy technologies to mature."

Dr. Nancy Kete, 202-729-7600

Director of Climate, Energy and Pollution program at World Resources Institute; member of the "Fueling the Future" editorial review board

"This study makes a compelling and well-reasoned case for expanding the role natural gas plays in the U.S. energy economy, the means by which this can be achieved and the advantages of doing so.

"Especially noteworthy is the emphasis on 'total energy efficiency,' or TEE, as the most practical and effective means of achieving a significant (17%) increase in the natural gas component of a 'clean energy portfolio.' From my own experience at Ontario Hydro, I strongly support the case the WPA study makes for TEE and its benefits in both environmental and economic terms.

"I also applaud the emphasis the study places on the economic and security benefits of a major increase in the role of natural gas for meeting domestic energy needs."

Maurice Strong, 416-498-3150

Chairman of the Earth Council and senior advisor to the United Nations and the World Bank; member of the "Fueling the Future" editorial review board

What the Media Are Saying

"Fuel cell fever has spread to some normally staid utilities, sending their stocks soaring as investors snap up shares in what many see as the power source of the future. Fuel cells, which proponents say will eventually provide power for everything from cellular phones to automobiles and homes, generate power electrochemically from hydrogen or methane without combustion.

"Commercial applications of fuel cell technology are still two to four years away, but investors are banking on future potential in the same way that they poured funds into money-losing Internet stocks, analysts said."

Nigel Hunt

Reuters, Jan. 21, 2000

"Investors have been piling into a handful of utility stocks, charged up by, of all things, their Internet-related and technology investments.

"Investors have focused on moves by these companies into fuel cells that make electricity through an electrochemical process, new solar power materials or Internet-based service companies.

"So it has come to this: The Internet is transforming even lowly utilities, the stodgy stock-market sector that investors for so long have loved to ignore."

Rebecca Smith

"Utility Stocks Get a Charge from Internet," The Wall Street Journal, Feb., 8, 2000

Clinton Library Transfer Form

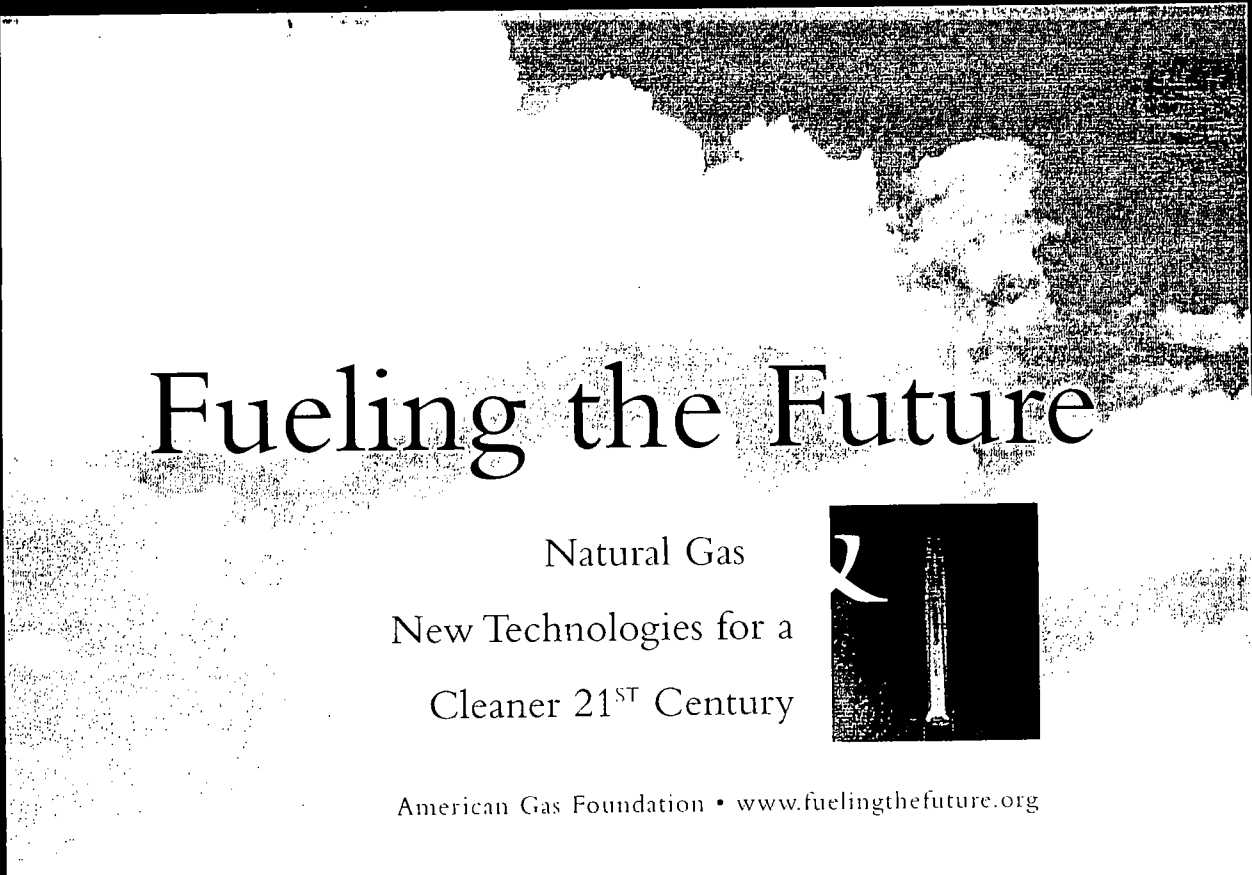
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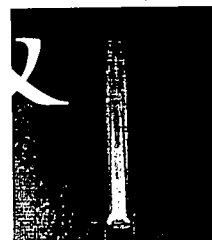
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Fueling the Future

Natural Gas
New Technologies for a
Cleaner 21ST Century



American Gas Foundation • www.fuelingthefuture.org

To Drive Natural Vans & Wagons

REASON #6: OUTSTANDING PERFORMANCE, ROOM & VERSATILITY

Open the door of a natural gas Dodge Ram Van or Wagon and the first impression is...space! Ram Vans & Wagons feature impressive people and cargo-hauling capability, with the capacity to carry up to eight people, while the Ram Maxi

Wagon comfortably transports up to fifteen. Unibody construction allows increased payloads. Range on natural gas is impressive: 200-225 miles in the city; 250-300 miles on the highway. And the heavy-duty, gas-charged shock absorbers, along with the front stabilizer bar, have been computer-matched to the wishbone-type independent front suspension for smooth, straight-tracking performance.



Dodge Ram Wagon

"SO, WHY NOT DODGE NATURAL GAS VEHICLES FOR YOU?"

More and more fleets are taking advantage of the benefits of running natural gas vehicles, including:

- Shuttle Operators
- Gas Utilities
- Government Fleets
- Local Delivery Fleets
- Medical Facilities
- Military Bases
- Corporate Fleets, both large and small
- Schools and Universities
- And many, many more...

Natural gas Dodge Ram Vans & Wagons may be just right for you, too. Contact your local Dodge dealer, or call the DaimlerChrysler Fleet Operations Hotline at 1-800-999-FLEET for more information today!

MORE GREEN FOR YOUR WALLET

Fleets can realize substantial operating savings by using natural gas-powered Dodge Ram Vans & Wagons. Consider that, at the time of printing, the cost of natural gas was about 30 percent less than gasoline on a national average. So fleets that run a significant number of miles on natural gas, such as airport shuttle services, can potentially save \$2,000-\$3,000 (or more) per year per vehicle. And larger fleets of 30 to 40 vehicles could experience cumulative savings of up to \$100,000 or more per year on fuel. Multiply that by the service life of a vehicle, and the savings become even more impressive.

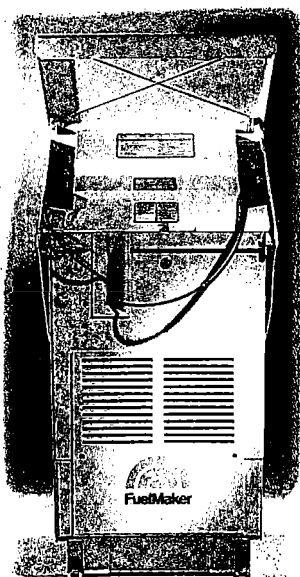
A little quick math and you can determine how your fleet can save on operating expenses by switching to natural gas.

REFUELING? EASIER THAN YOU THINK!

The natural gas delivery system is already in place. More than 1.2 million miles of pipeline supply natural gas to virtually every part of the country. And the refueling infrastructure continues to grow with nearly 1,500 natural gas refueling sites currently in operation around the country...with more being added every month. For availability information and the location of refueling sites in your area, visit the Department of Energy's Alternative Fuel Data Center web site at www.afdc.doe.gov. Additional information is also available from the Natural Gas Vehicle Coalition at (703) 527-3022. Or visit their web site at www.ngvc.org.

If you're looking to increase productivity, on-site refueling can be a viable option as well. Refueling appliances such as the FMQ Series

from FuelMaker Corporation can provide either time-fill or fast-fill options, depending on individual fleet requirements. Such on-site refueling programs enable fleets to purchase natural gas directly from their local utility, which further decreases fuel costs and reduces employee downtime associated with refueling off-site. And all DaimlerChrysler natural gas vehicle customers are eligible for a 10% discount off the manufacturer's suggested list price for FuelMaker compressors. To find out more about on-site refueling contact FuelMaker Corporation at 1-800-898-3835.

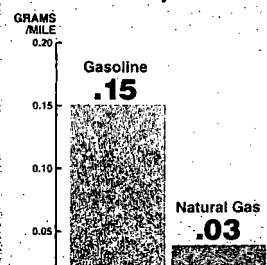


FuelMaker Corporation offers flexible natural gas refueling systems that can accommodate fleets using either time-fill, fast-fill, or a combination of both. On-site refueling capability can increase efficiency, saving both time and money.

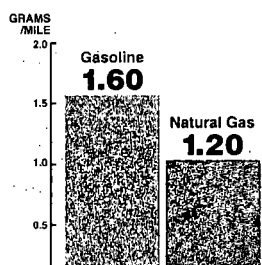
- **Clean Burning**
- **Efficient Operation**
- **Abundant Fuel Supply**

Because domestic supplies of natural gas are plentiful, DaimlerChrysler natural gas vehicles can help meet low emissions standards while, at the same time, help reduce operating costs and increase energy security. These graphs demonstrate DaimlerChrysler's natural gas emissions advantage.

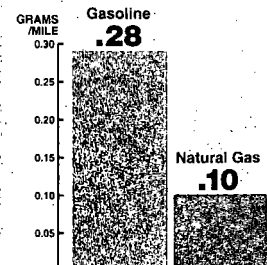
EMISSIONS COMPARISON Non-Methane Hydrocarbons



EMISSIONS COMPARISON Carbon Monoxide



EMISSIONS COMPARISON Nitrogen Oxide



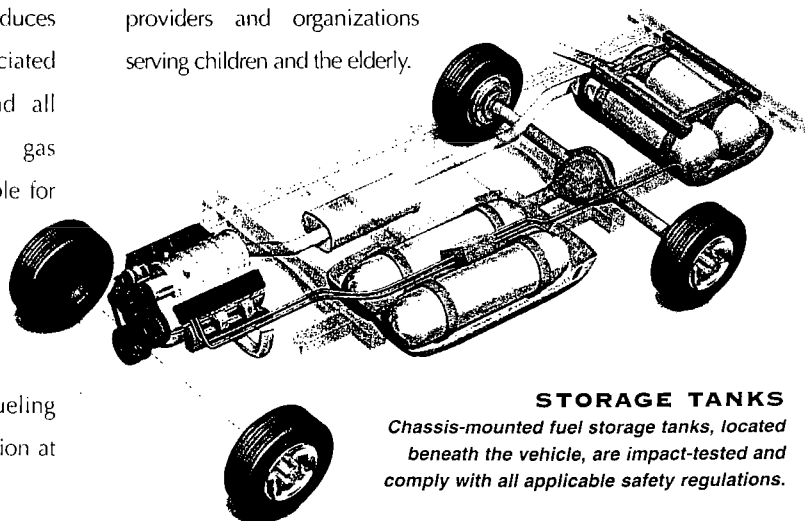
Data are for comparably equipped gasoline and natural gas Dodge Ram Vans and Wagons.

THE NATURAL CHOICE FOR A VARIETY OF FLEETS

With fleet managers being required under the Clean Air Act (CAA) and Energy Policy Act (EPACT) to purchase increasing numbers of alternative fuel vehicles, now is the time to put Dodge's tough and versatile natural gas-powered Ram Vans & Wagons to work. Airport shuttles, van pools, delivery trucks, couriers, utilities and vans for trades such as plumbers, electricians and carpenters are ideal applications for these DaimlerChrysler-developed, dedicated natural gas vehicles. Other potential users include government fleets, military bases, environmental and public service organizations, educational institutions, health care providers and organizations serving children and the elderly.



Distinctive decals identify the owner as an environmentally responsible citizen.



STORAGE TANKS

Chassis-mounted fuel storage tanks, located beneath the vehicle, are impact-tested and comply with all applicable safety regulations.



Angela C. Mizeur

11/09/99 06:17:26 PM

Record Type: Record

To: Roger S. Ballentine/WHO/EOP@EOP

cc:

Subject: Fritts mtg

the attendees tomorrow at this mtg with Fritts and The American Gas Association:

Charles Fritts

Julie Kabous

Murray Liebman

Charles Estes

George Williams

**AMERICAN GAS ASSOCIATION
Fax Transmission**

**CHARLES H. FRITTS
Vice President
Government Relations
400 North Capitol Street, NW
Washington, DC 2001
Ph.: (202) 824-7220
Fax: (202) 824-7092
cfritts@aga.com**

DATE: October 26, 1999

**TO: Mr. Roger S. Ballentine
Deputy Assistant to the President
For the Environmental Initiative**

PHONE NO.: (202) 456-7782

FAX NO.: (202) 456-1736

The American Gas Association (AGA) is familiar with the Administration's overall concerns with emissions reductions as well as enhanced energy efficiency.

In the event of additional funding, attached is the Natural Gas Industry Research Development and Demonstration (RD&D) request. Our funding recommendations are consistent with the Administration's concerns with the environment and system reliability.

It is unfortunate we will not be able to meet and discuss the attachments further today. However, if you have any questions, please feel free to contact me at 202 824-7220. I look forward to seeing you at the rescheduled meeting date of Wednesday, November 10th, at 10:00am.

This Facsimile consists of 4 pages.

“A New Climate For Reliability”

Overall Energy System Optimization, Reliability & Emissions Reductions \$ 8 million

- Optimization of energy production and delivery systems
- Natural gas cooling
- Distributed generation
- Reduction in methane vented or leaked during production, transmission, distribution or utilization

Enhanced Energy Efficiency \$ 10 million

- Industrial process efficiency improvements
- Combined Heat & Power and Cooling /CHP
- Fuel cells for building and industry applications
- Fuel cell / turbine hybrids

Fuel Substitution \$ 12 million

- High efficiency gas prime movers
- Increased natural gas supply
- Expanded transmission & distribution infrastructure

Total	\$ 30 million
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Total

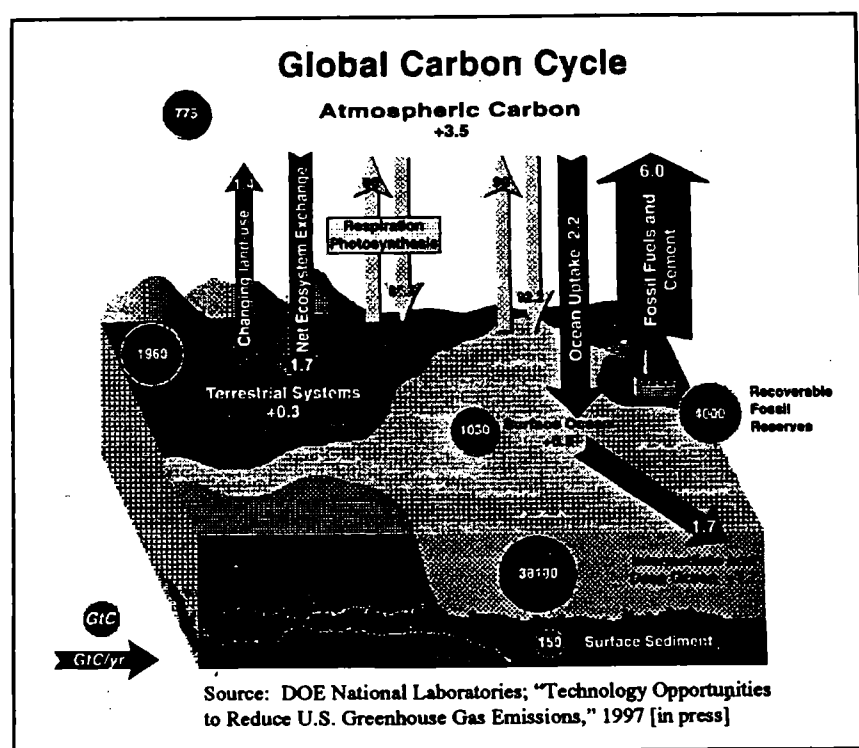
\$ 30 million

“A New Climate For Reliability”

	Energy Systems Optimization, Reliability and Emissions Reductions	Enhanced Energy Efficiency	Fuel Substitution	Greenhouse Gas Reduction
<u>TECHNOLOGY</u>				
Optimization of Energy Distribution Systems	✓	✓	✓	✓
Natural Gas Cooling	✓		✓	✓
Distributed Generation	✓		✓	✓
Reduction in Methane Vented or Leaked	✓	✓		✓
Industrial Process Efficiency	✓	✓	✓	✓
Combined Heat & Power and CCHP	✓	✓	✓	✓
Fuel Cells for Buildings and Industry	✓	✓	✓	✓
Fuel cell / Turbine Hybrids	✓	✓	✓	✓
High Efficiency Gas Prime Movers	✓	✓	✓	✓
Increased Natural Gas Supply	✓		✓	✓
Expanded Transmission & Distribution Infrastructure	✓		✓	✓

Responding To The Challenges Of Controlling Greenhouse Gas Emissions:

A Comprehensive Natural Gas Technology Implementation Strategy



November 1997

**Gas Industry
RD&D Initiative**

Responding to the Challenges of Controlling Greenhouse Gas Emissions:

A Comprehensive Natural Gas Technology Implementation Strategy

The Role of Natural Gas in Reducing Greenhouse Gas Emissions

The United States is a major contributor to emissions of greenhouse gases that are potential contributors to global climate change. The primary greenhouse gases that are emitted by industrialized nations are carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), chloroflourocarbons (CFCs), and ozone. Industrial activity leads to incremental emissions of these gases primarily through the mining/drilling, production, transport, and use of fossil fuels. CFCs, now being phased out, are primarily used for electric vapor-compression air conditioning and refrigeration. Ozone is produced at ground level by photochemical reactions of NO_x, CO, and volatile organic compounds (VOCs). NO_x, a product of combustion of fossil fuels, is thus not a primary greenhouse gas, but is indirectly implicated by its contribution to ground-level ozone formation.

Of the fossil fuels in common use, natural gas is the lowest CO₂ generator and can be burned in such a way as to minimize N₂O emissions. (In fact, it has been verified in testing that high-temperature natural gas combustion does not produce *any* N₂O.) Its production and transport does result in minimal amounts of CH₄ release to the atmosphere. The carbon content of the major fossil fuels is:

Coal	25.5 Million Metric Tons of Carbon (MTC) per Quad
Petroleum	20.0 MTC/Quad
Natural Gas	14.4 MTC/Quad

For this reason, substitution of natural gas for coal or petroleum is often cited as an element of any strategy for reducing greenhouse gas emissions.¹

Natural gas has already achieved a major role in the U.S. as the fuel of choice for industrial process heating, steam generation, and home heating. It has more recently become the fuel of choice for new electric generation plant construction. However, it enjoys only about a 25 percent share of the current national energy mix. Greater use of natural gas as the fuel of choice for industrial applications and in the existing electric generation mix and petroleum in the industrial, residential, and transportation market sectors will be required if natural gas is to play an increasing role in any national strategy to reduce greenhouse gas emissions. Such changes will only be possible through a combination of technology improvement and policy implementation.

¹ See for example:

US EPA; "Natural Gas: Can it Play a Major Role in Limiting Greenhouse Warming?" Global Change Division; November 1989.

National Research Council; "Confronting Climate Change;" 1990.

US DOE; "Scenarios of U.S. Carbon Reductions;" 1997.

International Gas Union; "The Role of Natural Gas in Climate Change;" 1997.

A Natural Gas Technology Strategy is a Strong Option

The Clinton Administration has acknowledged that the U.S is a major source of the greenhouse gas emissions that can cause climate change and announced plans to make a comprehensive technology strategy a cornerstone of a plan to reduce greenhouse gas emissions. A recent study by five Department of Energy (DOE) laboratories has shown that development and introduction of new energy technologies can significantly reduce greenhouse gas emissions and is also economic.² The study corroborates similar findings by the National Research Council.³ As noted above, expanded use of natural gas is an element of each of these studies. Natural gas technology must be a key element of any comprehensive national technology strategy. This proposal presents a plan of action that allows the federal government and the natural gas industry to work hand-in-hand to implement this important component of the national strategy.

Elements of the Natural Gas Technology Strategy

Any comprehensive technology strategy to reduce greenhouse gas emissions must address four elements – substitution of lower carbon fuels, increased efficiency of energy use, reduction in energy service demand, and control of emissions caused by the production, delivery, and use of energy. The proposed natural gas strategy addresses all four of these elements. Further, the strategy addresses the need to develop and commercialize new technical solutions and transfer these solutions in the U.S. and to other nations.

Fuel Substitution

The direct one-for-one substitution of natural gas for coal or petroleum results in immediate reductions in carbon dioxide emissions of 44 percent and 28 percent, respectively. While price incentives or carbon tax penalties can be used to encourage fuel substitution, selective technology improvement is a more effective strategy. The development of new or better natural gas technologies can result in economic, market-driven substitution. Of course, policy initiatives can be applied to reduce the risk of application of new technology and accelerate the rate of substitution of lower carbon natural gas. Key elements of the strategy to make natural gas the fuel of choice in more applications include:

- Gas cofiring with coal in existing electric generation and industrial boilers
- Advanced high-efficiency gas turbines to repower existing coal-burning facilities and for new-capacity generation facilities
- Natural gas vehicles using both conventional internal combustion engines and hybrid gas engine/electric drives
- Production of liquids from natural gas (e.g., DME) to fuel conventional or hybrid diesel vehicles
- Natural gas cooling technology to replace peak period electricity use (and displace CFC and HCFC electric cooling technology)
- Micro-cogeneration technologies with very high efficiencies for residential and commercial systems

² USDOE; "Scenarios of U.S. Carbon Reductions;" 1997.

³ National Research Council; "Confronting Climate Change;" 1990.

Expanding the use of natural gas cannot be done without significant expansion of the supply and transportation network. An expanded infrastructure could drive fuel costs up and defeat the goal of an economic, market-driven response to reduction of greenhouse gases. New technology is a critical element of a strategy to increase supply availability (and avoid transmission and distribution bottlenecks) at competitive prices. The proposed comprehensive plan addresses these needs as well with the following elements:

- Advanced exploration technology to expand overall economic resources
- Lower cost drilling, completion, production, and processing technology
- New high-pressure pipe technology, compressors, and systems to increase pipeline capacity
- Lower-cost installation techniques to deliver gas to new customers at low cost

Energy Efficiency

Energy efficiency is a key element of the proposed program. Efficiency improvements provide immediate benefits in the form of lower fuel costs, reduced carbon emissions, and reduced emissions of other air pollutants. While much progress has been made through GRI and DOE R&D over the past two decades, further significant improvement can yet be made. Programs in this proposal include:

- Industrial process heating
- High-efficiency industrial/utility boilers
- Very high efficiency hybrid fuel cells/gas turbines
- Low-cost, very high efficiency fuel cells for application in distributed electricity generation

Reducing the Demand for Energy and Fossil Fuels

Consideration of overall systems and how energy is used can lead to reductions in the demand for energy services. Furthermore, the integration of fossil fuels and renewable energy sources can lead to important reductions in greenhouse gas emissions. The natural gas technology strategy includes several important elements to address these needs:

- Gas/solar water heating and electric generation
- Biomass and landfills as carbon-neutral fuel gas sources

Overall Gas Energy System Optimization and Emissions Reduction

In parallel with the strategy of increasing natural gas use in efficient and economic ways, it will be important to operate the natural gas system in the most efficient way, such that emissions of greenhouse gases during the exploration, production, transport and use of natural gas are minimized. Technology programs include:

- Methane emissions reduction in production and transport of natural gas
- Methane emissions measurement and control techniques
- Natural gas technology greenhouse gas emissions management
- Increased-efficiency gas compression; optimal use of gas and electric compressor drives
- Zero emissions industrial park design

- Optimization of capacity utilization across the national transportation grid
- Optimal trading of natural gas and electricity to minimize overall greenhouse gas emissions
- Development of hybrid gas and electric systems to allow overall energy use optimization

Technology Transfer and Deployment

A global response to greenhouse gases requires that the U.S. implement efforts to transfer economic technology solutions to other nations. The technology base developed in the U.S. also has the potential to create domestic employment opportunities. This comprehensive plan includes an element of international technology transfer that would focus initially on technologies such as:

- Natural gas transmission piping and compression
- Coal-seam methane recovery and use
- Natural gas high-efficiency industrial burners and boiler equipment
- Combined cycle electric generation
- Natural gas storage and transport from remote gas locations to new power plants in developing economies without a gas pipeline transportation grid
- Industry-led initiatives to encourage deployment of CO₂ or CFC reducing technologies

Funding the Comprehensive Program

Much important R&D related to the above critical technology areas is already funded by the federal government and the gas industry. This comprehensive plan intends to rely in large part on the existing U.S. Department of Energy (DOE) gas-related RD&D program (funded at \$194 million in 1999), recommended additions to this program by the Gas Industry RD&D Initiative (an increase to \$293 million in 2000), the gas industry program funded through the Gas Research Institute (GRI), and, to a lesser extent, internal R&D within the gas companies. However, these programs fall short of the required funding for several of the key technology areas described above.

To address this shortfall, the industry proposes that the federal government fund a joint government/industry R&D program to be managed by GRI and the gas industry. A \$100 million per year combined DOE/GRI/gas industry program for four years is proposed.

As shown in the first column of Table 1, GRI proposes that \$74.3 million of the \$100 million program be managed by GRI as a joint program. Federal funding of \$37 million annually of incremental government funds would be matched by \$37.3 million of GRI and gas industry funds. Such a joint program, managed by GRI, has several major advantages. First, it takes advantage of the existing program management infrastructure and strategic gas industry advisory process available through GRI. It also allows for complete coordination with other industry and government R&D. GRI and DOE already carry out joint planning activities through a process specified in a Memorandum of Understanding (MOU) that ensures coordinated activities on gas-related R&D.

The remaining \$26.4 million of the \$100 million program, shown in the DOE/Industry program column, represents incremental DOE/Industry-managed funds beyond the joint program needed to fulfill climate change goals indicated in the next section. These programs require \$20 million of DOE funds, supported with \$6.4 million of gas industry cofunding. Thus, the total DOE budget increment is \$57 million. Program budget details are provided later.

Table 1. Joint Program Funding Relationship (\$ in millions)			
Program Area	DOE/GRI/ Industry Funding	DOE/Industry Funding	Total
Fuel Switching			
End Use	30.5		30.6
Supply	22.2	0.8	23.0
Energy Efficiency	11.5	6.7	18.2
Demand Reduction	3.0	0.5	3.5
System Efficiency	5.8	6.4	12.2
Tech Transfer	1.3	12.0	13.3
TOTAL	74.3	26.4	100.7

Program Goals and Impacts

To be worthy of the substantial investment in new technology described above, the results must be measurable and significant.

Goals

This proposed program would seek to accomplish the following goals by the year 2015:

- Replace 8 Quads of coal used annually in U.S. electric generation and industrial boilers with 5.5 Quads of advanced natural-gas-fired combined cycle generation and small-scale gas-fired distributed generation or cogeneration. This is possible because advanced gas generation and cogeneration systems can operate at efficiencies of 55 to 70 percent, compared to existing coal facilities operating at 30 to 35 percent efficiencies. This represents a reduction of 125 million metric tons of carbon (MTC).
- Increase efficiency of current gas use by an average of 10 percent, cutting natural gas use by 2 Quads annually and reducing carbon emissions by 30 MTC.
- Replace 5 Quads annually of petroleum use in residential, industrial, and transportation markets with 5 Quads of natural gas, reducing carbon emissions by 28 MTC.
- Develop new, economic gas supplies to allow annual North American gas production to increase by 8 Quads annually.
- Develop sustainable renewable resources to provide (from biomass) or reduce (using solar) the need for natural gas production by 1 Quad annually, reducing carbon emissions by 14 MTC.
- Increase the natural gas transport and distribution infrastructure to carry an additional 8 Quads annually of gas supply to markets.

- Reduce and control gas industry methane emissions to a level of less than 1 percent.

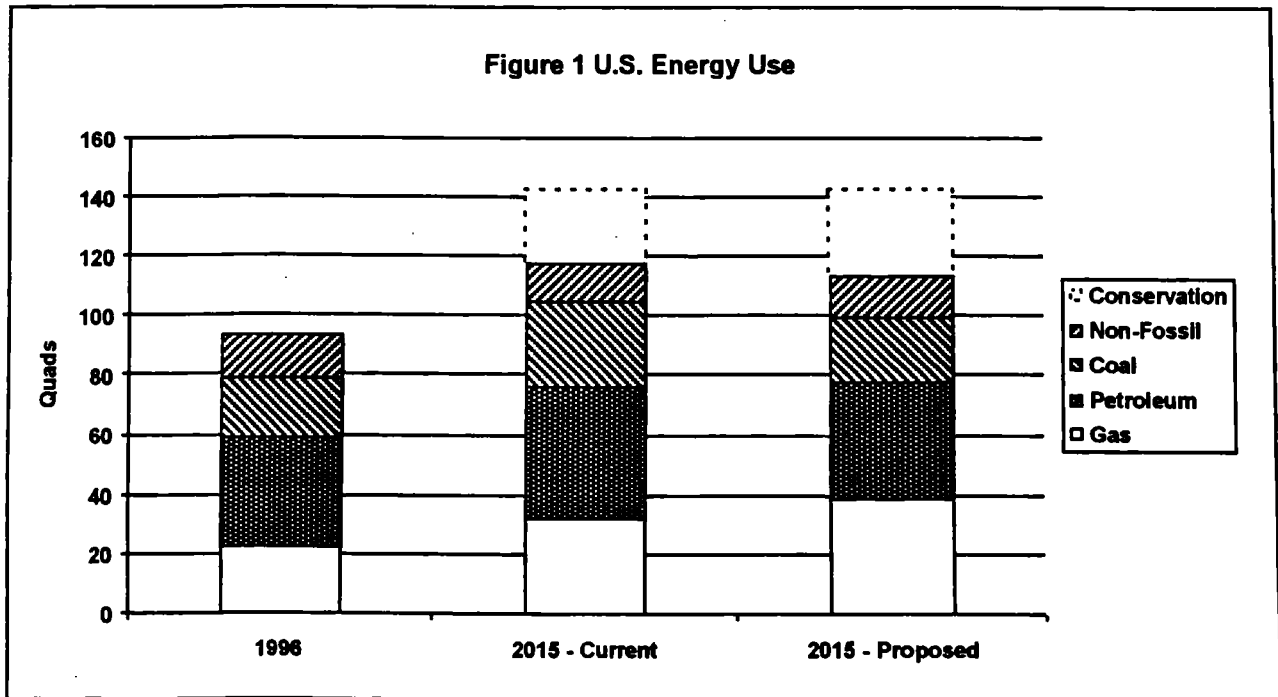
The net carbon emissions reduction impact from achievement of the above goals totals approximately 200 MTC. Figure 1 displays energy use and Figure 2 shows carbon emissions as currently projected by GRI and as impacted by the comprehensive program proposed by the gas industry.

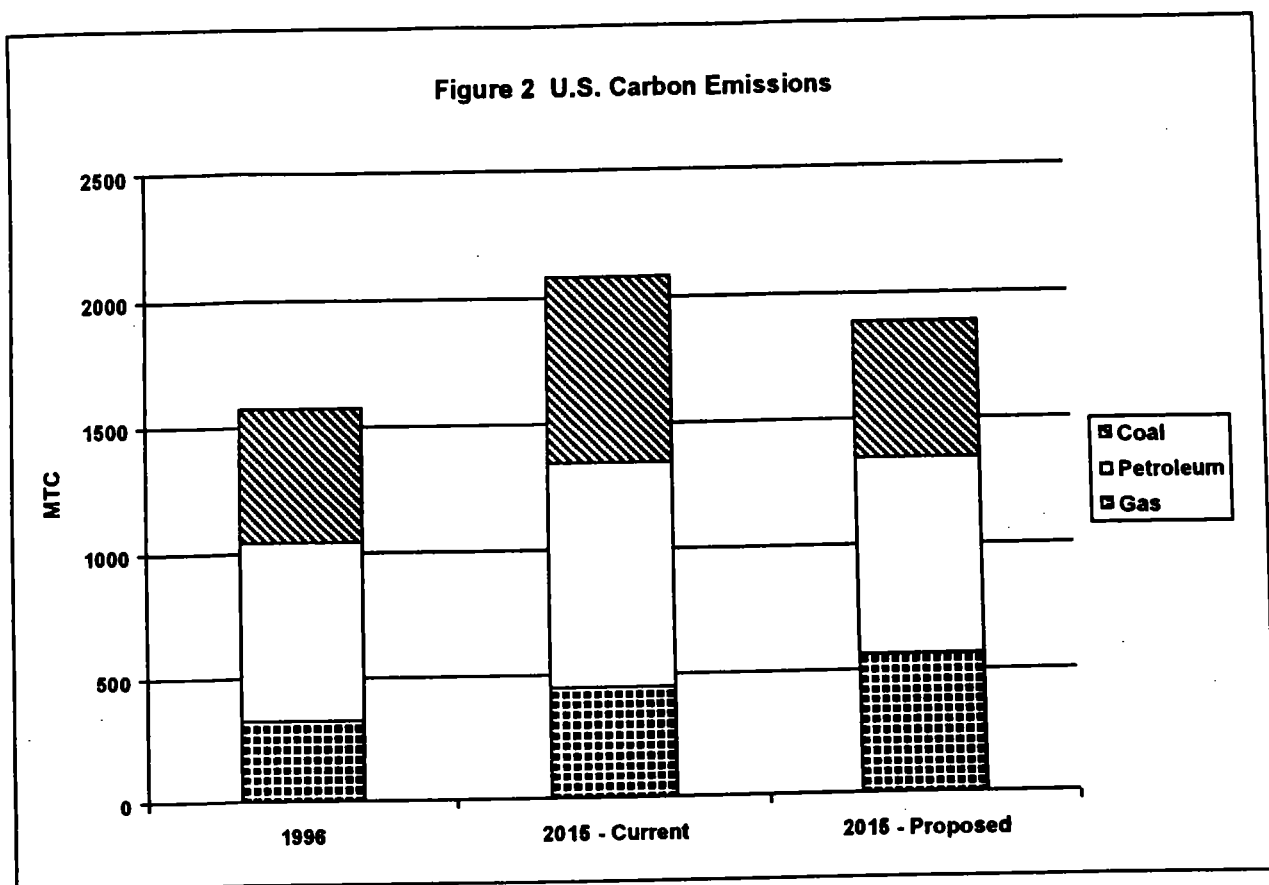
Figure 2 shows that while the proposed program reduces carbon emissions by some 200 MTC in 2015, U.S. emissions are still at a level greater than the 1996 level by almost 300 MTC. Of course, this proposal does not address efficiency improvements in petroleum use in industrial and transportation markets. Studies by others have shown significant potential in these sectors, particularly the transportation sector.

Economic Impacts

GRI has run its Baseline Projection model in order to determine the economic implications of an increase in gas production of approximately 8 Quads. The results are summarized as follows:

- To meet the larger gas demand, average lower-48 acquisition price, which nearly equals the average wellhead price increases by roughly 55 cents/MMBtu (or by roughly 27 percent) from an average of \$1.90/MMBtu to an average of \$2.45/MMBtu.





- The wellhead price impact is much smaller than some industry analysts expect. GRI estimates show that North America's resource base is substantial with many additional profitable investments available at relatively small price increases. Additional producer revenues permit the greater exploration and development activities that are required to exploit the resource necessary to meet the new demand.
- The average lower-48 transmission cost is nearly the same in this sensitivity case and the base case. Expansion of existing facilities and new facilities are required to supply the new, incremental demand. Investments in new pipeline facilities increase total transmission costs, but unit costs are kept in check because the total costs are spread over additional gas demand.
- The 2015 revenue requirement for pipelines increases by approximately \$5 billion (or by 34 percent) from \$15 billion to \$20 billion. The change is attributed to investment in new facilities and O&M and fuel costs to support those facilities. By 2015, an additional 35 Bcfd of pipeline capacity is added at a capital cost of \$24 billion. The additional capacity is spread fairly evenly throughout the lower-48.
- Burner-tip prices increase by an average of 40 cents/MMBtu (or by 10 percent) from \$3.60/MMBtu to nearly \$4.00/MMBtu. This change is attributed entirely to an increasing cost of gas at the wellhead. Declining unit costs for transmission and distribution keep the increase of burner-tip prices in check. Average burner-tip prices do not increase nearly as much as burner-tip prices in individual markets because the contribution of the power generation sector to the average grows over time as power generation gas demand grows in proportion to total demand. Therefore, residential and commercial burner-tip prices can be expected to grow by larger amounts than industrial and power generation burner-tip prices

primarily because there is only limited demand growth in these sectors to offset the larger costs that occur throughout the gas supply chain. Gas substitution in these sectors is largely offset by increased gas use efficiency.

- Lower-48 production increases by approximately 7Tcf (or by 25 percent) from 26 Tcf to 33Tcf by 2015. By 2015, Canadian production increases by approximately 2Tcf (also by 25 percent) from 8 Tcf to 10 Tcf. By 2015, the largest changes in production occur in the following regions:
 - Appalachian production increases by 0.5 Tcf (or by 38 percent) primarily because the higher prices increase the development of Devonian shale resource, mostly located in Appalachia.
 - Rocky Mountain (Forerange) production increases by 1.9 Tcf (or by nearly 80 percent) because the higher prices increase the development of tight gas resource, prevalent in the Rocky Mountains.
 - Production in the Gulf of Mexico increases by over 3 Tcf (or by nearly 40 percent). The Gulf is relied on heavily because its developable resource is large when compared with developable resource in other regions.
 - Production in Alberta, Saskatchewan, and Manitoba increases by 1.5 Tcf (or by 22 percent). The developable resource in these regions, where the Western Sedimentary Basin is located, is also large compared with developable resource in other regions.
 - Eastern Canada and British Columbia production increases by nearly 1.3 Tcf (or by over 100 percent). Much of the deliverability for these regions was unused in the base case because limited pipeline capacity constrained flow. In this sensitivity, the higher levels of demand and price justify new pipelines from these regions. The additional pipeline capacity permits greater gas production, increasing deliverability utilization to levels that are more compatible with utilization levels in other regions.
- By 2015, much of the increase in demand (i.e., 6.0 Tcf) is satisfied by production from high-permeability, conventional gas resource, mostly located in the Gulf of Mexico and the Western Sedimentary Basin in Canada. This resource is a significant part of the future resource that will be developed.
- By 2015, the percent increase in low permeability, shale, and coalbed methane production averages more than 40 percent, a significant change from the base case. Development and production of this marginal resource is much more attractive at the higher prices that occur at larger consumption levels.

International Implications

The natural gas strategy described herein is a robust strategy for many other nations around the world. The International Gas Union⁴ estimates that the worldwide supply of natural gas is 404,400 Billion cubic meters (14,000 Quads). Worldwide usage of natural gas is about 2,100 Bcm (75 Quads). Thus, this resource base represents a 187-year supply at current usage and a nearly 100-year supply even if gas usage were to double worldwide.

The U.S. can play an important role in reducing worldwide greenhouse gas emissions by developing and exporting natural gas supply, delivery, and use technologies.

⁴ International Gas Union; Report of Committee J; "World Gas Prospects, Strategies, and Economics;" 20th World Gas Conference; June 1997.

Program Elements

Table 2 shows the specific program budget lines for the proposed program and relates these to the strategic elements described above. Both total joint GRI/DOE/Industry and the DOE/Industry programs and funding are shown. Program elements are described in detail in the following sections. The federal funding requirement and GRI/gas industry cofunding are also delineated.

Program Management

The Gas Research Institute proposes to manage the \$74.3 million of the total initiative as a single program. GRI management has several important benefits. Most importantly, it provides for efficient program planning and implementation. GRI is already established to manage its 50 percent share of the funding; management costs for the federal funding component are proposed at 10 percent of the federal funding level of \$37 million, or \$3.7 million per year. Management costs are included in the budgets shown in Tables 1 and 2. This management fee includes access to the highly regarded GRI advisory process to provide expert industry advice to program planning and implementation. Furthermore, the management plan simplifies contract negotiation and performing organizations. GRI proposes the government negotiate a single cooperative agreement with GRI for multi-year program funding and implementation.

The specific research elements of the proposed \$74 million joint program to be managed by GRI are designated by an asterisk on Table 2.

Table 2. Program Elements and Budgets (Millions of \$)

Program Element		Total Annual Budget	Federal Budget	GRI Cofunding	Gas Industry Cofunding
I. Fuel Substitution					
A.	Industry/Utility Cofiring/Reburn *	1.5	0.5	1.0	
B.	Advanced High-Efficiency Gas Prime Movers *	15.2	8.0	7.0	0.2
C.	NGVs, incl. Hybrid Vehicles *	7.35	4.0	3.0	0.35
D.	Gas R/C Cooling, Appliances, and Micro-Cogeneration *	6.5	3.5	1.5	1.5
E.	Expanded Supply *	18.5	6.0	12.5	
F.	LNG Conversion: Remote Sites	0.75	0.75		
G.	Expanded T&D Infrastructure *	3.7	2.2	1.0	0.5
II. Energy Efficiency					
A.	Industrial Process Heating *	1.5	0.5	1.0	
B.	High-Efficiency Ind./Util. Boilers*	5.5	3.0	2.0	0.5
C.	High-Eff. Glass Melting	3.5	2.0		1.5
D.	~~Methane Reburn: Forest Prod.~~	2.8	1.5		1.3
E.	High-Efficiency Surface Comb.	0.4	0.25		.15
F.	Fuel Cells *	3.5	2.5	1.0	
G.	Very High Efficiency Hybrid Fuel Cells/Turbines *	1.0	0.5	0.5	
III. Reducing the Demand for Energy and Fossil Fuels					
A.	Gas/Solar & Gas/Biomass *	3.0	2.0	1.0	
B.	Fuel Cell/RV/Distributed Gen	0.5	0.5		
IV. Overall Energy System Optimization and Emissions Red.					
A.	Reduction of Vented Methane Emissions *	1.75	1.0	0.75	
B.	Methane Leakage Reduction *	2.0	1.5	0.5	
C.	Systems Optimization *	1.0	0.5	0.5	
D.	Natural Gas Technology Greenhouse Gas Mgmt. *	1.0	0.5	0.25	0.25
E.	NOx Abatement and Eff. Impr. for Engines and Burners	6.4	6.0		0.4
V. Technology Transfer & Deployment					
A.	International Tech. Transfer *	1.3	0.8	0.5	
B.	Natural Gas Industry Challenge	1.5	1.5		
C.	Res.Gas Cooling Joint Marketing	7.0	5.0		2.0
D.	School & Inst. Bldg. Desic. Init.	3.0	2.0		1.0
E.	Design Comp. : Gas Cooling	0.5	0.5		
GRI/DOE/Gas Industry Subtotal (*)		74.3	37.0	34.0	3.30
DOE/Gas Industry Subtotal		26.35	20.0	0.00	6.35
Totals		100.65	57.0	34.0	9.65

* Joint Program to be Managed by GRI.

Program Element I. Fuel Substitution

I. A. Industry/Utility Cofiring/Reburn

Application: Industrial and utility boilers throughout the nation

Benefits of Technology: Natural gas cofiring reduces CO₂, NO_x and particulate emissions from coal, biomass, and waste-fueled boilers; increases boiler efficiency; and enables operators of boiler facilities and power plants to comply with environmental regulations economically and safely. Replacing 20% of coal use with natural gas in a boiler reduces CO₂ emissions by approximately 8%; efficiency improvements (including reductions in parasitic losses) further reduce CO₂ emissions.

Program Description: Industrial and utility boiler operators that use a non-gas primary fuel face a number of challenges to economically meet the increasingly stringent environmental regulations and generate the required steam loads reliably as their equipment ages. Natural gas cofiring with the primary fuels (e.g. coal, biomass, waste sludge) can be a relatively low-cost technology to meet the requirements in environmental compliance, operation, and performance characteristics. The gas burners help enhance mixing of combustion gas inside the boiler, resulting in more complete combustion. Early field tests proved that the emission levels of nitrogen oxides (NO_x), sulfur dioxide (SO₂), and residual ash were significantly reduced by displacing 5-30% of the primary fuels with natural gas cofiring through engineered burner systems. Due to the increased hydrogen content of methane compared to oil and coal, less CO₂ is released per unit of energy output. However, this inherent advantage from a climate change perspective also results in slightly lower thermal efficiencies, in that the latent thermal energy of the water produced during combustion of natural gas is not captured in the boiler. This thermal energy loss is more than offset, however, by the reduction in parasitic loads (e.g., auxiliary power consumption for coal and ash handling) necessary particularly for coal-fired boilers. (These parasitic losses would be similar for both utility and industrial boilers.) Results (going from 0% to 75% natural gas cofiring) from the Conesville 3 wall-fired 165-MW unit, for instance, verified that, while boiler-only thermal efficiencies decreased from 89% to 87%, **overall** thermal-to-electric system efficiencies, including boiler efficiencies and parasitic losses, increased slightly from 42.6% to 42.7%. (This could be further increased in an optimized system.) The key market barrier to expand the gas cofiring technology is the general lack of field data and system optimization and application know-how by the boiler community. Steam generation is the largest energy consuming process sector and the general boiler population maps closely with the national demography. Federal government should cofund a joint RD&D effort to refine and expand the market application of this technology. This low-cost technology would provide the wide spread environmental and efficiency benefits to the general public of every corners of the nation.

Development Status: GRI and other organizations have supported significant efforts to develop prototype gas cofiring systems and conducted limited field tests that validated significant environmental and some efficiency benefits. Further efforts are needed, however, to increase the efficiency of these boilers when fired or cofired with natural gas. To overcome the initial market entry hurdles, further effort will be required to refine the technology and validate the operating performance in various targeted market sectors (fuel types, boiler sizes and designs, industry segments). In addition, an aggressive technology transfer campaign will also be needed to commercialize the technology to the boiler engineering consultants, burner manufacturers, gas industry, and boiler operators.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	500	500	500

Cofunding from GRI of about \$1 million per year can be anticipated from this effort.

I. B. Advanced Gas-Fired High Efficiency Prime Movers

Applications: Research and development is needed to increase the efficiency of gas-fired prime movers for power generation and cogeneration to allow economic substitution of gas technologies for higher carbon generation technologies.

Benefits: Reductions of emissions of CO₂, NO_x, SO₂, hazardous air pollutants, and particulates can be expected (in an optimized system) by increasing the efficiency of advanced prime movers. Even at the same efficiency levels, the combustion of natural gas emits less CO₂ per unit of energy than other fossil fuels. The CO₂ emissions from coal are nearly double those of natural gas, and emissions from oil are over 45% higher than gas. In addition to reducing CO₂, natural gas used in place of coal and oil reduces emissions of NO_x, which, while not a greenhouse gas in itself, is a precursor to ground-level ozone formation, a greenhouse gas.

Program Description: The technology options available today for prime-mover-based power generation include steam and gas turbines, diesel cycle, and Otto cycle engines. Steam and gas turbines are available in a wide range of sizes, from hundreds of kilowatts to hundreds of megawatts. Simple-cycle efficiencies range from 15-20% for small-scale turbine systems, to 20-40% for large-scale systems. For instance, the GE 135-megawatt MS7001F gas turbine, with a turbine inlet temperature of 2,300°F, has an efficiency of 33%. The latest commercial offering, the GE 7G, offer efficiencies of 39.5% in the 240 to 280 megawatt range. Diesel electric systems are available in the size range of tens of kilowatts to 20 megawatts. Diesel efficiencies range from 15-25% for very-small-scale systems to 30-40% for small-scale systems. Otto cycle (gasoline-fired) electric engines are available from 1 kilowatt to hundreds of kilowatts. Efficiencies range from 5-10% for micro-scale systems to 15-25% for very-small scale systems. Thus, there is a market for all three types of prime movers. Otto cycle systems are predominant and offer the highest efficiencies in the 1-10-kilowatt size range; diesel cycle systems in the 10-kilowatt-to 20-megawatt size range; and turbine cycles above one megawatt. Particularly as the market moves toward smaller-scale distributed generation systems, the Otto and diesel cycles may offer attractive options. There are challenges, however, in terms of cost, reliability, and emissions.

Reciprocating engines have been in commercial use for many decades. However, reciprocating engines operating on natural gas face unique challenges. Natural gas is not as combustible as diesel fuel, and so pilot ignition or other means are necessary to allow fully dedicated natural gas diesel cycles to operate. R&D challenges include the cost and complexity of the pilot ignition technique, the possibility of knock in diesel engines, potential coking problems with the standard diesel injector due to reduced cooling, and higher emissions level than even standard diesel cycles. Otto cycle engines have of course been in use for almost one hundred years for automobiles. Larger-scale, unattended use of Otto cycle engines for power generation face a number of challenges, including meeting emissions requirements, noise restrictions, and reliability and maintainability needs for unattended sites.

The Collaborative Advanced Gas Turbine (CAGT) Program focuses on aeroderivative (i.e., derived from aircraft engines) gas turbines. In terms of a flexible, midsize (30 - 150 MW) gas turbine, the major technical challenges are to: reduce costs to 20-40% lower than combine cycle systems, increase efficiency of a simple cycle system to 45-50%, develop a quick-start capability, meet NO_x requirements, have high availability, and achieve low O&M costs. The large-scale CAGT and flexible midsize turbine efforts are currently being funded by DOE and so are *not* proposed for additional funding under this climate change initiative.

Small (less than 20 MW) gas turbines offer many favorable characteristics, clean, quiet operation, and low maintenance requirements. However, the relatively high equipment cost and low efficiency of small gas turbines presently on the market for cogenerator sets are barriers to the

commercial feasibility of the technology. To overcome these barriers, low-cost components must be used and a simple, low-cost means for improving turbogenerator efficiency, for instance, by using exhaust heat recovery. One option is to use technologies such as thermochemical recuperation and catalytic combustion to achieve both increased efficiency (by preheating with turbine exhaust) and NO_x reduction.

The potential for small gas turbines to be competitive with electric drives and other small engines is contingent on their first cost and efficiency, as well as their reliability, durability, and emissions control. The proposed program will have technical goals of increasing system efficiency to 40% and reducing NO_x levels to less than 5 ppm, at competitive first costs. For instance, commercially available reciprocating engines, operating in this size range, have efficiency levels of 15-35% and NO_x emissions levels of 90 - 150 ppm. Of course, a 45% reduction in CO₂ can be expected per unit of output, simply by conversion from oil to natural gas, even at the same efficiencies.

Reciprocating Engines: Major efforts need to be targeted at reducing the capital cost of diesel and Otto cycle engines for stationary applications. Reliability, maintenance, and availability issues also need to be dealt with for unattended operations. Revolutionary advances are needed to bring costs down from the current \$300/kW to \$200/kW. R&D consortia are already working on retrofit kits for diesel cycle engines, so DOE efforts in this area are not required at this time. Advanced components, like long-life spark plugs and ceramic valve seats for Otto cycle engines and pilot ignition components for diesel cycle systems, need to be developed for reciprocating engines. Major emissions challenges must be met if stationary reciprocating engines are to be allowed to operate in such areas as the Southern California basin. In particular, engine optimization to run on natural gas and catalyst lifetime extension research is needed.

Advanced engine development work under a Department of Defense engine research program has proven proof of concept of a high-compression-ratio diesel engine with direct injection of fuel. The simple mechanical design of a high compression ratio diesel engine allows compression ratios of 40:1 to be used and thermal efficiencies of greater than 55% to be achieved. High pressure injectors, extremely lean operation, and turbulence in the combustion chamber should produce engine emissions less than one tenth of the emissions of lean burn engines and a fraction of the emissions of clean gas turbines. The technology needs to be adapted for natural gas.

Development Status: Both GRI and EPRI have been funding gas turbine research for at least a decade. GRI's efforts are focused on simple-cycle systems in the less-than-20-MW size range. For instance, GRI's industrial turbine program has as its goals systems efficiency targets of 38% and NO_x emissions of less than 8 ppm. Microturbine (tens to hundreds of kilowatts), Stirling engine, and rotary engine R&D have been terminated. GRI emphasis has been on R&D on aeroderivative and industrial turbines to reduce emissions for distributed generation and cogeneration applications.

EPRI efforts are focused on combustion turbines, repowering, and dispersed generation. EPRI's emphasis has been on cost reduction, operating guidelines, blade life management, and software modules (like their State of the Art Power Plant -- or SOAPP -- software module). GRI and EPRI are collaborating on ceramics for combustion turbines, SOAPP module development for small combustion turbines, and the collaborative aeroderivative gas turbine (ICAD).

GRI has also performed extensive RD&D on dedicated natural-gas-fueled Otto and diesel cycle engines for stationary applications. The focus has been on revolutionary components and on systems cost reduction. Diesel system emphasis, for instance, is on developing a pilot ignition component, lower engine maintenance costs, and develop a retrofit kit (mentioned above) for diesel generation sets. One experimental Otto cycle engine (a GM-454) modified to run on natural gas and with catalysts achieved NO_x levels of 0.05gm/Hphr, less than Southern California

Air Quality Management District limitations, but the lifetime of the catalyst has been verified thus far at only 400 hours, much less than needed for even one year's operation.

High pressure, direct natural gas injectors need to be developed for high compression ratio diesel engines. The engine and injector technology has been patented but needs to be reduced to practice for natural gas engines.

Federal Funding Requirements (\$1000):

	<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
Gas Turbines	5000	5000	5000	5000
Reciprocating Engines	<u>3000</u>	<u>3000</u>	<u>3000</u>	<u>3000</u>
Totals	8000	8000	8000	8000

GRI and gas industry cofunding of \$6.2 million per year for gas turbines and \$1 million per year for reciprocating engines R&D can be anticipated.

I. C. NGVs, including Hybrid Vehicles

1) Improved CNG and LNG Technologies for Medium- and Heavy-Duty Vehicle Applications

Application: Primary applications in medium-duty (10,000lb to 26,000lb GVW) and heavy-duty (over 26,000lb) vehicles. Markets include transit and paratransit buses, refuse haulers, over-the-road line haulers, and package delivery trucks. These vehicles currently operate mostly on diesel and gasoline.

Benefits: By operating vehicles on CNG or LNG rather than traditional fuels (gasoline and diesel), emissions of NO_x, CO, and CO₂ can be reduced. CO reductions of over 50 percent can be realized when comparing natural gas to gasoline; and under cold temperature or aggressive driving conditions, CO reductions of 90 percent can be realized. On an energy-equivalent basis, natural gas should produce more than 20 percent less tailpipe CO₂ emissions than gasoline or diesel. The emission values will vary depending on combustion efficiency in each application.

Program Description: RD&D to enhance medium-duty and heavy-duty natural gas engine efficiency; to integrate engine, on-board fuel storage, and fueling systems. R&D will also target on-board storage systems (to enhance safety and minimize methane emissions).

Development Status: Natural gas vehicles and engines are available today from a number of manufacturers. RD&D to enhance engine efficiencies (narrowing the gap between diesel and natural gas engine efficiencies) and vehicle integration to even further improve vehicle performance and economics.

2) Natural Gas Hybrid Applications

Application: Hybrid natural gas/ electric engines can have applications in many vehicle types. Transit buses are currently targeted to gain the most benefit from this technological approach.

Benefits: Major increases in system efficiency. Reduced CO₂, CO, and NO_x emissions over traditional fuels. Advantages over electric vehicles in extending driving range and increased engine power.

Program Description: Super-ultra-low emission, high fuel efficiency, electric hybrid natural gas vehicle development. As one option, a small gas turbine/fuel cell system should be investigated. While very high efficiencies (over 60%) are possible, the cost and reliability implications of this combined system need to be evaluated.

As another option, the feasibility and economics of using natural gas to produce di-methyl ether (DME) will be evaluated. DME-fueled vehicles, as hybrids or in place of diesel, offer emission advantages over fossil fuels and range advantages over electric vehicles.

Development Status: Both efforts are in the applied research stage.

Federal Funding Requirements (\$1000):

	<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
1) CNG & LNG	2000	2000	2000	2000
2) Hybrids	<u>2000</u>	<u>2000</u>	<u>2000</u>	<u>2000</u>
Totals	4000	4000	4000	4000

GRI and gas industry cofunding of \$2.35 million per year for MD/HD vehicles and \$1 million per year for hybrid vehicles can be anticipated.

I. D. Natural Gas R/C Cooling, Appliances, and Micro-Cogeneration

Application: Reduce energy service demand through building systems, controls and a low-cost housing systems initiative. Increase energy efficiency through the deployment and use of micro-cogeneration, gas cooling, refrigeration, desiccants, low-capacity gas heating and efficient gas appliances. There is also the potential for the use of natural gas as an alternative fuel to electric and oil in water heating through the use of solar-assisted gas water heaters and combination space/water heating systems, and the displacement of wood with advanced gas hearth products.

Benefits: More-efficient residential and commercial equipment will reduce CO₂ in the residential and commercial building sectors near term by 20 percent, and long term by greater than 50 percent; add low-skill domestic jobs in the manufacturing sector; and reduce base energy service demand in residential and commercial sectors. Natural gas cooling also displaces CFC and HCFC, potent greenhouse gases.

Program Description: To reduce energy service demand the work will focus on building automation, systems optimization, and mechanical systems integration to reduce both building energy service demand and greenhouse gas emissions without compromise to occupancy safety and indoor air quality. To increase energy efficiency the focus will be on component reliability, improved product performance, and reduced emissions to displace electric or fossil fuel systems with high efficiency technologies. To use natural gas as an alternative fuel the focus will be on replacement of electric resistance, oil, and wood space and water heating with gas technologies to achieve a near-term reduction of greenhouse gas emissions.

Technology options for micro-cogeneration include phosphoric acid, proton exchange membrane, molten carbonate, and solid oxide fuel cells. Issues of first cost, efficiency, packaging, integration, and maintenance of the less-than-50-kW systems must be addressed.

Development Status: The status of the proposed efforts is summarized below.

- Reduce energy service demand - building systems and controls are near commercialization or in the latter stages of development. The low-cost housing system initiative is in the idea generation stage.
- Increased energy efficiency -
 - Micro-cogeneration is in the initial stages of development.
 - Gas cooling, refrigeration, and desiccants - Large commercial systems are at or near commercialization, with advanced commercial systems and residential technologies still in development phase.
 - Low-capacity heating - In early issues identification.
 - Efficient gas appliances - Research varies from initial issues identification to near product introduction and includes system optimization, improved component and burner design of both residential and commercial appliances.
- Use alternative fuels - Most technologies are at or near commercialization; solar-assisted water heater requires technologies assessment.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
3500	3500	3500	3500

GRI and industry cofunding of \$3.0 million per year can be anticipated.

I. E. Advanced Technologies for Expanded Natural Gas Resource Base

Application: RD&D of technologies needed to improve availability of reliable and economic natural gas supply to meet increased gas demand over next 10 to 15 years.

Benefits: There is much discussion today regarding the issue of global climate change and the implications to the use of natural gas. The discussion suggests that offsetting other fossil fuels with natural gas could be pursued as one important element in a strategy to reduce the effects of global climate change. However, this implies that adequate supplies of natural gas be economically available to meet the required increased demand. Confidence in the ability to increase natural gas production is based on the view that the U.S. natural gas resource base is of sufficient size and quality and that it is accessible and extractable within tolerable economic bounds. Current trends and many resource projections are suggesting that most of the future supplies of natural gas will come from lower-permeability and deeper formations and from vast off-shore developments in order to meet future gas needs. These expanded resource base environments will present even greater technical and economic challenges than in historical gas supply operations. New advanced technologies targeting quantity evaluation, accessibility, extractability, and quality improvement in these expanded resource base environments will be necessary in order to help ensure economically adequate supplies of natural gas in an overall strategy to mitigate global climate change.

Program Description: GRI manages a Natural Gas Supply RD&D Program with the overall objective of reducing the unit cost per Mcf of natural gas recovered at the well, providing lower-cost reliable gas supply to gas consumers. The program is segmented into the following technology areas addressing the technical and economic challenges of quantity evaluation, accessibility, extractability, and quality improvement:

Quantity Evaluation - Emerging Resource Evaluation, Advanced Seismic, Formation Evaluation, and Reservoir Geology

Accessibility - Emerging Resource Evaluation, Advanced Seismic, Formation Evaluation, Reservoir Geology, and Supply Environmental Management

Extractability - Stimulation, Completion, and Drilling Technologies

Quality Improvement- Offshore Gas Processing and Subquality Natural Gas Upgrading

Development Status: The current program has been developed to address the natural gas supply challenges of an approximately 7 to 10 Tcf increased U.S. gas demand per year in the years 2010 to 2015, over 1995 production technology capabilities. Significant progress has been made to date in the areas of coalbed methane, advanced stimulation, secondary gas recovery, and multi-variable control technologies to name a few. However increased gas demands, driven by strategies to reduce global climate change, will require appropriate incremental investments in these advanced technology areas.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
6000	6000	6000	6000

GRI cofunding of \$12.5 million per year can be anticipated.

I.F. LNG Conversion from Remote Sites

Application: Conversion of small, isolated or low-quality sources of methane, which might otherwise be vented, to high-value LNG for heavy-duty transport vehicles. Sources could include landfill or underground coal mine sites.

Benefits of the Technology:

- Provides economic value to pollutant/resource whose recovery is currently not economic at many sites.
- Would provide competitively-priced domestic LNG, with little net environmental cost, to displace less-benign petroleum fuels.
- Reduces potential for methane venting from remote wells and landfills.

Technology Description: Development of small, modular, skid-mounted gas processing equipment to recover, clean up and convert landfill gas and coal mine methane from premining degasification systems and gob wells to LNG. This technology could also be applied to remote gas wells or to conventional natural gas distribution systems to produce LNG in the range of 500 to 3,000 gallons per day.

Nationwide, landfill gas emissions total more than ten million metric tons of methane; coal mining contributes nearly four million additional tons.¹ Together these sources emit the greenhouse gas equivalent of approximately one million tons of CO₂ each day. Development of an economically attractive process to capture even ten percent of the waste methane from these two sources would be of significant benefit to the environment in terms of abatement of potential methane venting and in terms of cleaner transportation fuel substitutes.

Development Status: While research to reduce the cost of small LNG conversion systems would be beneficial, technology *per se* is not an obstacle. Federal sponsorship of a few "first of a kind" demonstration units and support for market entry activities are the primary requirements to initiate what should subsequently be a self-sustaining industry built on waste reduction.

Federal Funding Requirements (\$1000)

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
750	5000	5000	—

¹Emission of Greenhouse Gases in the United States, 1995-, USDOE, EIA; p. 31.

I. G. Expanded/Renewed Transmission & Distribution Infrastructure

Application: This research focuses on developing technologies to cost effectively expand the piping infrastructure and to maintain the integrity of the current system when the transportation volumes are increased. Increased use of the natural gas transmission and distribution system requires new piping installations, raised pressures, increased pipe diameters, and more facilities including valves, regulators and meters. Increased system automation is also required.

Benefits: Lower-cost piping systems to install the new mains and services required by an expanded distribution system are being developed by GRI. These systems include new pipe materials, more productive installation procedures, and lower-cost joining technologies. The integrity of the current system is maintained with pipe renewal technologies developed by GRI that are more cost effective than replacing older pipe. Additionally, GRI is developing technologies to reduce the costs of sealing cast iron joints.

Program Description: GRI has worked closely with the gas industry to reduce the costs of installing new mains and services. GRI developed guidelines for the cost-effective use of large diameter coiled polyethylene (PE) pipe to install mains with fewer joints. Further research is necessary to increase the productivity of new pipe installation including the PE pipe coil loading process. GRI has produced guidelines and test equipment for reliable PE fusion operations. Further research is needed on the induction fusion joining technology to lower the cost of some types of fittings. For entirely new systems, horizontal boring is a low-cost attractive technique. However, obstacle detection systems must be improved. GRI has introduced pipe renewal systems to the industry to reduce the costs of replacing older pipe. Research is needed on new materials that support high pressures and add structural integrity to the renewed pipe. For renewing and upgrading the infrastructure, candidates insertion techniques include blown-in soft, flexible liners and slip lining with PE pipe. For maintaining the existing infrastructure, internal methods to seal cast iron joints from natural gas loss can reduce costs and methane emissions. Monitoring and preventing third-party damage, the primary pipe failure mechanism, can minimize methane release due to accidents. GRI has developed a communications architecture that can be implemented by the gas industry for system automation and increased communication with the meter and the customer, with potential large impacts on energy use. For transmission systems, the use of lower-cost composite pipe material needs to be investigated as an alternative to high-strength steel.

Development Status: Research on coiled PE pipe and induction fusion will be complete in 1998. The development of high-pressure piping materials is expected to continue through 2002. An evaluation of materials with the required high pressure and structural integrity for renewing pipe begins in 1998. Once a material is identified, testing and development will follow. Technology to internally seal cast iron joints is currently being developed in the laboratory and will be completed in 1999. GRI has developed and commercialized a composite pipe repair technique for steel transmission piping, but all- or partial-composite piping research for new piping systems is still needed.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
2200	2200	2200	2200

GRI and gas industry cofunding of \$1.5 million per year can be anticipated.

Program Element II. Energy Efficiency

II. A. Industrial Process Heating Efficiency Improvement Program

Application: Broad process heating applications in the majority of industry sectors

Benefits: Improved process heating efficiencies would result in: substantial reduction of CO₂ and NOx emissions in major industrial process heating applications throughout the nation, and improved energy efficiency in the most energy intensive industrial end use sectors.

Program Description: The industrial sector is the largest end use market for energy. The traditionally older, energy intensive industries (food, pulp and paper, chemicals, refining, stone, clay, and glass, and primary metals) are the ones that are responsible for the majority of the emissions throughout the nation. Various technologies were developed by GRI and other organizations that could be advanced and applied in many industrial processes and equipment in these major industrial sectors to reduce emission, increase efficiency, and improve the overall competitiveness of the U.S. industries. Federal government should cofund a joint RD&D effort with the industry to make most use out of these advanced technologies which are at various stages of the RD&D cycle. Examples of these technologies include increased-efficiency, low-emission burners, controls, sensors, and advanced materials for high-temperature heating applications in steel, glass, and cement market sectors and low-temperature heating applications in chemicals, refining, pulp and paper, and food market sectors. Specific activities of the joint program should include: additional research and development to refine these technologies, improve the reliability, reduce the capital cost; additional field tests to validate the operating performance in targeted applications; and broad technology transfer to equipment manufacturers and end users. The joint program could provide the critical funding resources required to address different market barriers encountered in the initial commercialization of these promising advanced technologies and benefit the end users and general public.

Development Status: GRI and other organizations have supported significant efforts to develop several combustion technologies that have crosscutting process heating applications, including infrared burners, regenerative burners, and ceramic fiber matrix burners. These technologies include low-emission burners for high and low temperature processes, infrared radiant burners, advanced gas reburn, sensors, and high-temperature materials. Federal funding in this program will provide the critical resources to successfully bring these technologies to broad commercial application.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	500	500	500

GRI cofunding of \$1 million per year can be anticipated.

II. B. High Efficiency Industrial/Utility Boilers

Application: Industrial and Utility Boilers throughout the nation

Benefits: Use of this technology will result in: a) improved boiler and power plant efficiencies; b); substantial reduction of NO_x and particulate emissions for majority of large scale boilers and c) allowing operators of boilers and power plants to comply with current and future environmental regulations economically and safely.

Program Description: Many of the industrial and utility boilers in current use are decades old, operating with very low efficiencies. RD&D is needed to offer low-cost retrofits and new boiler and burner options that can increase boiler efficiencies to over 90%. Currently, the commercially available low-NO_x boiler burners can only achieve 15 ppm with sporadic successes at a cost that most boiler operators are reluctant to pay. The objective of this technology is to develop a cost-effective ultra-low-NO_x burner and the required control sensors to reliably achieve NO_x emission levels below 5 ppm. This low-emission combustion technology also seeks to significantly improve the boiler efficiency since the burners will incorporate advance sensor systems to achieve the flame stability required for safe operation under very tight combustion ratio control. As the majority of the boiler facilities ages beyond their prime performing years, this reliable and cost-effective technology presents a realistic approach to substantially reduce the NO_x and particulate emissions throughout the nation. The Federal government should cofund a joint RD&D effort with the industry on this project since the general public at large will be the most obvious beneficiary of this much needed reliable low-emission combustion technology.

Development Status: GRI has developed and commercialized the innovative Donlee boiler that operates at efficiencies of 80-85%. Additional improvements in boiler efficiency to over 90% are needed. GRI, IGT, and other organizations have supported significant efforts to develop prototype high-efficiency, ultra-low-NO_x burner will require the development of compatible advanced flame sensor technology to achieve the operational stability required for safe operation. Further prototype development and field validation on the burner and flame signature sensors will be required to reliably achieve the 5 ppm ultra-low emission goals.

Conceptual design of an 85% efficient cyclonic water-tube boiler with emissions of less than 9 ppm has been completed. Further development and field testing of this design is required.

Laboratory evaluation of a forced internal recirculation boiler has been conducted. Goals are over 90% efficiency and less than 10 ppm of NO_x emissions. System testing is required.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
3000	3000	3000	3000

GRI and industry cofunding of \$2.5 million per year can be anticipated.

II. C.1 High-Efficiency Glass Melting

Application: Fiberglass can be produced in a highly efficient, compact melter which produces very low levels of NO_x and CO emissions, indirectly implicated in global warming through their contributions to ground-level ozone formation. Melter technology can also be applied to resin-coated fiberglass scrap recycle.

Benefits of the Technology:

- High thermal efficiency using low-cost natural gas for fuel
- Very high heat and mass transfer rates
- Very low NO_x and CO emissions
- Low capital cost

Technology Description: In submerged combustion melting, natural gas and oxidant (preheated air, enriched air, or oxygen) are fired directly into and under the surface of the bath of material being melted. Combustion products bubbling through the bath provide very effective heat transfer, increasing thermal efficiency and reducing the overall temperature of the gases and thus reducing NO_x formation. The bubbles increase bath turbulence, which promotes melt composition homogeneity. Any carbon or organic material in the feed is thoroughly utilized through combustion, further enhancing thermal efficiency and reducing CO emissions. System energy efficiency is also improved over conventional glass furnaces because the submerged melter can be started up and shut down in only a few hours.

Development Status:

- Commercial units making 3 ton/h of mineral wool are in operation in Ukraine and Belarus.
- IGT has licensed SCM for application outside the former Soviet Union.
- 500 lb/h oxy-gas or air-gas fired pilot melter constructed at IGT.
- Demonstrations of mineral melt production set to begin.
- Commercial partnerships and funding in negotiation.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
1000	1000	---	---

Gas industry, manufacturer, and end user cofunding of \$1,000,000 per year is anticipated.

II.C.2 High-Efficiency Glass Melting

Application: NO_x reduction and production rate increase from glass melting furnaces

Benefits of the Technology:

- Enhances heat transfer by up to 10%, which will directly reduce CO₂ emissions due to the efficiency improvements.
- Reduces NO_x by up to 70%
- Applies to both air-fired and oxy-fired furnaces
- Retrofits easily to existing burners and furnaces at very low cost

Technology Description: High-temperature, natural gas-fired furnaces, especially those fired with preheated air, produce large quantities of NO_x per ton of material processed. Oscillating combustion involves the creation of successive, NO_x-formation-retarding, fuel-rich and fuel-lean zones within the furnace. Heat transfer from the flame to the load (and, therefore, furnace productivity) increases due to the more luminous fuel-rich zones and the breakup of the thermal boundary layer, thus increasing efficiency. This patented technique involves the forced oscillation of the fuel flow rate to the furnace. When oxygen is used, its flow rate may also be oscillated, but out-of-phase with the fuel. Heat is removed from the zones before they mix to reduce overall peak flame temperature, thus reducing NO_x formation.

CeramPhysics, Inc. is adapting its solid state proportioning valve for commercial application to oscillating combustion. A prototype valve has been successfully tested by IGT. This valve has demonstrated that it reliably generates the flow rate pulses at the frequencies needed to implement oscillating combustion.

Development Status:

- Patents issued (U.S. Pat. Nos. 4,846,665 and 5,302,111; European Pat. No. 0524880A1)
- Bench-scale air-gas tests on one burner completed - 70% NO_x reduction, 10% heat transfer increase
- Pilot-scales oxy-gas tests completed - 70% NO_x reduction
- Oscillating valve scale-up completed - currently available at 2x10⁶ Btu/h per valve

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	1000	1500	1500

Gas industry, manufacturer, and end user cofunding of \$500,000 per year is anticipated.

II. D. Methane Reburn for Forest Products

Application: Emissions reduction and efficiency improvement for waste wood and biomass-fired stoker boilers

Benefits of the Technology:

- Increased efficiency, which will result in CO₂ reduction.
- Reduced NO_x emissions - 50 to 70%.
- Reduced CO₂ emissions and eliminated ammonia slip Least expensive alternative method of NO_x reduction.

Technology Description: In the METHANE de-NO_x reburn process, natural gas is injected directly into the primary combustion zone just above the combustion grate thereby reducing the availability of oxygen and preventing NO_x formation. Efficiency increases of up to 5% are possible with this process. This is in contrast to conventional reburning, where natural gas is injected above the primary combustion zone after the majority of NO_x has been formed. In METHANE de-NO_x therefore, a significant part of NO_x precursors decompose and react in the primary combustion zone, forming molecular nitrogen rather than NO_x. Overfire air is injected high enough in the furnace to allow sufficient residence time for reburning reactions to reduce NO_x and its precursors before the remaining hydrocarbons and carbon monoxide are completely combusted. As a result, METHANE de-NO_x can provide greater NO_x reductions than conventional reburning methods.

Development Status:

- U.S. patents 5,307,746 and 5,020,456 and 5,205 to IGT
- Field evaluation of METHANE de-NO_x reburn for MSW operation at Olmsted County demonstrated:
 - Increased boiler efficiency - 2.5%
 - Reduced emissions - NO_x reduced by 60%, CO reduced by 50%
 - Reduced excess air - 50%
- Evaluated reburn technology at Cogentrix owned 240 MW coal-fired cogeneration plant in Richmond, VA
 - Cogentrix operating with METHANE de-NO_x reburn since July 1996
 - Cogentrix plans to retrofit 7 more boilers (400 MMBtu/h) at Richmond site

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
1500	1500	500	---

Gas industry, manufacturer, and end user cofunding of \$1,300,000 per year is anticipated.

II. E. High-Efficiency Surface Combustor

Application: Heating of thermally sensitive process fluids or steam production

Benefits of the Technology:

- High Efficiency because of high heat transfer rates, 95%
- Uniform Temperature - no hot spots or degradation of the fluid
- Compact - lower cost and small footprint
- Ultra-Low Emissions - < 9 vppm NO_x, < 50 vppm CO, long-term goal

Technology Description: The surface combustor-heater is a combined combustion/heat-transfer device in which the heat-exchange surfaces are embedded in a stationary bed of refractory material and where gaseous fuel is burned within the interstices of the bed.

The overall heat transfer, and thus efficiency of the process, from the products of combustion to the load is significantly enhanced because of the intense combined heat convection, radiation, and conduction. Consequently, the combustion temperature is lowered, resulting in lower levels of NO_x compared to conventional systems. The increased thermal inertia and temperature uniformity make the surface combustor-heater ideal for raising steam or heating water.

Development Status: Bench-scale experimental program evaluated mechanism of combined convective/radiative heat transfer and interaction with combustion products.

Demonstrated:

- high combustion intensity, 800,000 Btu/h-ft²
- high heat transfer rates, 1 00,000 Btu/h-ft²
- high energy conversion density, 800,000 Btu/h-ft³
- ultra-low emissions, NO_x < 15 vppm, CO < 50 vppm), short-term goal
 - U.S. Patents 5,375,563 and 5,476,375 issued to IGT
 - R&D agreement and joint pilot scale development program initiated with TAKUMA Co. LTD, testing planned for 1998
 - Computer model developed for design and optimization

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
250	500	750	750

Gas industry, manufacturer, and end user cofunding of \$150,000 per year is anticipated. Additional cofunding from manufacturers is possible.

II. F. Fuel Cells

Application: Fuel cells at the scale of 0.2 MW to 2 MW will find application in two distinct markets - meeting the commodity heat and power needs of commercial and industrial sector facilities via onsite cogeneration, and meeting the high reliability/high electronic clarity electric power needs of "mission critical electric loads" within manufacturing and data processing operations. These two markets contain distinct competitive issues and both place very different values on the heat and power services that fuel cells provide.

Benefits: Fuel cells have the highest electrical efficiency, ranging upwards from 36% (HHV), of any power generation equipment in this size class. (The specific electric conversion efficiency varies by fuel cell design type.) In cogeneration applications, total fuel cell system efficiency approaches 80% (HHV). As incremental global warming reduction impacts are directly proportional to the relative efficiencies of fuel cells versus other available equipment in this size range (reciprocating engines and gas turbines), fuel cells offer between 10% and 50% reductions in fuel use per unit electrical output. Specific global warming reduction potential would then be calculated based on fuel supply cycle and fuel substitution assumptions.

Note that all cogeneration systems have roughly the same overall thermal efficiency, as any inefficiencies in the prime mover electrical conversion can be captured downstream in the system heat recovery system and converted into useful thermal outputs. However, for simple-cycle applications, these efficiency differences are significant. Yet the greatest impact from fuel cells may not be the incremental electrical efficiency improvement, instead, the almost emissions-free operation, very low noise and vibration, compact footprint and very high reliability (as proven in the field with the initial generation of phosphoric acid cogeneration systems), could likely stimulate the growth of the onsite cogeneration market. It is this increased penetration of this application, with its extremely high net fuel utilization, that would produce the significant increases in national end-use energy efficiency. Fuel cells carry the potential to make these small, onsite systems commercially practical and aesthetically invisible.

Various market studies estimate the potential size of the 2-MW and under, onsite cogeneration market to be from 50,000 to 75,000 MW, or 10 to 15% of the currently-installed U.S. fossil-based generating capacity. For comparison, the currently-installed cogeneration capacity (less than 10 MW unit size) is 4600 MW, so there is presently a relatively low market share, with much room to grow. The entire commercial/institutional energy market consumes about 1/3 of total U.S. electricity production. There is a great interest at present in Distributed Power Generation; in many cases, this 'new' application appears to be migrating rather rapidly towards onsite cogeneration, though with new ownership/financing/operating structures.

Program Description: Solid oxide fuel cell (SOFC) component/materials development, subscale system/cell stack testing, and full-scale testing. Technical feasibility, reliability, first cost, and system integration are key issues. Also, investigation of the feasibility of micro-cogeneration (under 50 kW) systems will be conducted. This investigation will address cost, packaging, integration, and institutional issues.

Development Status: Fuel cells fall into two broad classes: emerging commercial products that employ Phosphoric Acid technology (PAFC), and developmental systems that employ molten-carbonate (MCFC), ceramic SOFC, or proton-exchange membrane (PEM). This proposal is for continued development of the SOFC, currently in the basic research stage at GRI.

Federal Funding Requirements (\$1000):

	<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
Fuel Cells	4000	4000	4000	4000

GRI cofunding of \$1 million per year can be anticipated.

II. G. Hybrid Fuel Cell, Gas Turbine

Applications: R&D is needed to determine the technical feasibility of an ultra high-efficiency fuel-cell / gas turbine combined cycle system for small-scale power generation.

Benefits: Reductions of emissions of CO₂, NO_x, SO₂, hazardous air pollutants, and particulates can be expected in increasing the efficiency of advanced prime movers. Even at the same efficiency levels, the combustion of natural gas emits less CO₂ per unit of energy than other fossil fuels. The CO₂ emissions from coal are nearly double those of natural gas, and emissions from oil are over 45% higher than gas. In addition to reducing CO₂, natural gas used in place of coal and oil reduces emissions of NO_x, an indirect contributor to climate change. The projected fuel-to-electrical energy of this combined cycle hybrid system is 70 percent. Even the best combined cycle engine systems approach "only" 50 percent. This revolutionary advancement will offer the lowest CO₂ output per unit of delivered electricity available for any fossil-fuel-based system.

Program Description: In terms of hybrid systems, the gas turbine has a great potential for hybrid applications with advanced conversion devices. One area of primary interest is a natural-gas fuel cell / gas turbine hybrid system that can use the waste heat from the fuel cell to drive the gas turbine as a bottoming cycle. In this configuration, fuel cell waste heat is mixed and burned, raising the turbine inlet temperature. Studies, as indicated above, have projected that over 70% (lower heating value) thermal-to-electrical efficiency is possible in this configuration. The high efficiencies are possible because of the synergy between the solid oxide fuel cell (SOFC) and the small gas turbine. For instance, the turbine's compressor section can be used to pressurize the fuel cell stack, and the hot exhaust from the stack can be combusted and expanded to drive the turbine, extracting another 20-30% of heating value. Of course, having a low-cost (\$200-\$300/kW) small gas turbine is the key to the combined system's economics.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	500	500	500

GRI cofunding of \$500,000 per year in anticipated.

Program Element III. Reducing the Demand for Energy and Fossil Fuels

III. A. Integrated Natural Gas/Solar and Natural Gas/Biomass Technology

Application: Identification of approaches and technologies for developing integrated systems that provide non-interruptible energy by utilizing renewable energy sources in conjunction with natural gas. Develop high quality biomass to gas conversion and landfill gas processes and promote application of high efficiency, low emission gas technologies to biomass/landfill generated gas. Develop natural gas/biomass cofiring technologies that achieve higher energy efficiency than current biomass power plants.

Benefits: Enhances the viability of renewable energy sources by supplementing interruptible solar power and variable quality landfill or biomass gas with stable, high efficiency natural gas technologies. Development of integrated systems ensures optimal overall performance. Systems which utilize natural gas cofiring will offer higher efficiency and result in all key pollutants being decreased per unit of energy output.

Program Description: An integrated energy system that supplements solar power with natural gas will be developed that provides an non-interruptible power supply. Optimal gas technologies will be employed to ensure the highest efficiency and lowest emissions and provide the minimum environmental impact possible. Gas-based technologies will be examined to identify the best choice for integration into a solar-based energy system. Multi-phase effort may initially investigate multiple technology approaches with pilot scale development of one candidate system.

Technology issues associated with biomass conversion and landfill gas quality will be identified, with objective to optimize production and gathering of stable high quality gas. Issues such as unique contaminants or fuel quality associated with application of existing natural gas technologies to biomass/landfill gas will be identified with process solutions developed. Cofiring approaches for utilization of natural gas with biomass fired plants will be developed to increase energy efficiency and lower plant emissions.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
2000	2000	2000	2000

GRI cofunding of \$1 million per year is anticipated.

III. B. Fuel Cell/PV Distributed Generation

Application: Conduct case studies to estimate the value associated with customer-sited distributed clean generating technologies such as fuel cells and photovoltaics (PV) and propose mechanisms for apportioning these values in the marketplace.

Benefits of the Technology: Parallel goals exist for least-cost electric service to consumers, air quality management and global climate change mitigation, and a properly functioning competitive electric system. Performing case studies of the environmental and economic values associated with customer-sited clean generating technologies such as fuel cells and PV will provide guidance on how utilities, customers, and energy service companies should value such resources in a competitive market. Additionally, the study will facilitate air quality improvements and a reduction in greenhouse gases by increasing the role of these technologies in electric system planning.

Technology Description: Utility "load pockets" are one niche where fuel cells and PV are likely to make economic sense in the near term. A load pocket is an area that due to physical limits of the transmission or distribution system requires certain supplies of energy, operating, and installed reserves and related products from generators within that area.

A working group established by the New York State Department of Public Safety recently identified several load pockets in the New York metropolitan area. The in-city service territory of Con Edison constitutes a load pocket due to limitations on available transmission capacity to import competing sources of power. Within the in-city load pocket, Con Edison has identified additional load pockets: Astoria, Greenwood-Staten Island, Vernon, and the 138 kV transmission system within New York City. Because it is an island served by very limited transmission inter-ties, the LILCO service territory also constitutes a load pocket in which customers must receive service from generators on Long Island for all hours of the year. In addition, a number of sub-areas on Long Island are distribution constrained.

As the utility system becomes more competitive in New York, the emergence of fuel cells and PV as options for onsite generation by customers should provide competitive pressure to control prices within transmission- and distribution-constrained areas. However, in order to maximize economic efficiency, the value of the capacity that customer-sited onsite generators add to the local distribution and regional transmission system must be quantified and assigned in the marketplace. A determination of how these values should be divided between customers and energy service companies installing clean onsite generation, and distribution utilities avoiding infrastructure costs has not been completed.

Case studies of several fuel cell and PV applications will be conducted. Among those sites being considered for case studies are fuel cell applications at St. Vincent's Hospital and Sun Chemical on Staten Island and at the City of Yonkers waste water treatment facility, PV and fuel cell applications at the Durst Organization's 4 Times Square Project in New York (city), and PV sites at SUNY Farmingdale on Long Island, Rikers Island State Penitentiary, and Gun Hill Bus Depot in the Bronx.

The case studies will determine the capacity value of these applications, using data from utility partners such as local peak demand periods, costs of planned distribution and transmission capacity additions as well as projections of future market prices. The study will compare the performance and reliability of the customer-sited fuel cells and PV with local utility distribution system and regional transmission system load profiles. Specific values of these customer-sited applications (e.g. deferral of feeder or substation upgrades, reduction in distribution systems losses, improved customer power quality, and provision of voltage support and improved

reliability) will be quantified. Appropriate benefit/cost analyses as well as an assessment of potential environment improvements will be conducted.

Development Status: Data related to utility distribution loads will be collected with assistance from the utility partners. Fuel cell performance data in the areas identified as load pockets by the New York report will also be assembled. Irradiation and PV system performance data will be obtained from actual installed systems in New York City and on Long Island as well as from existing databases. Synthesis of utility load data and distributed technology performance will be conducted. Based on the results of the individual case studies, a methodology for assigning values of distributed technologies in a competitive electric market will be recommended.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	500	---	---

Program Element IV. Overall Energy System Optimization and Emissions Reduction

IV. A. Reduction of Vented Methane Emissions

Application: Technologies will be developed for reducing vented emissions from natural gas production, processing, transportation, storage, and distribution.

Benefits: Based on a comprehensive study by GRI and EPA, the natural gas industry emits approximately 314 Bcf of methane of which approximately 95 Bcf of methane is vented by the gas industry. This is equivalent to approximately 40 million tons of CO₂ and the lost gas is worth over \$200 million per year at current prices. The major sources of vented emissions from the gas industry are pneumatic control devices (31 Bcf), and "blow and purge" operations associated with maintenance activities (30 Bcf). A conservative estimate for the natural gas industry is that at least one-half of these emissions can be technically recovered and industry earnings can be increased by about \$80 million per year. Vented emissions from oil production contribute another 56 Bcf. The major sources from oil production are pneumatics (15 Bcf), chemical injection pumps (11 Bcf), and storage tanks (30 Bcf). At this point some information is available on methods for reducing vented emissions, but data are not currently available on the amount that can realistically be reduced, and the cost of applying these techniques. A conservative estimate for the oil industry is that around 50 percent of their methane emissions could be technically recovered which result in recovering approximately \$56 million per year worth of methane.

Increased use of natural gas in place of petroleum in vehicles can have a major impact on reduction of CO₂ from mobile sources. However, this benefit can be somewhat reduced by increased methane venting due to methane transport, storage, filling, and usage in NGVs.

Program Description: The goal of the program is to implement methods and technologies for reducing vented emissions from the natural gas industry. This will be accomplished by completing two major tasks, (1) identify sources of vented emissions and methods for reducing these emissions from the oil and gas industry, and (2) demonstrate these methods and collect data needed to perform a life cycle cost/benefit analysis, including capital, operating and maintenance costs, as well as data on effectiveness and durability.

Specifically, the program will focus on identifying technologies and methods to cost effectively reduce emissions from pneumatic control devices, chemical injection and dehydrators pumps, tanks, and blow and purge operations. Emissions from pneumatic control devices can be significantly reduced by using electric motors, compressed air instead of natural gas, or by replacing the continuous bleed equipment with newly developed low or non-bleed pneumatics. However data are needed on the costs of using these approaches under various implementation strategies. Measurements of pneumatic control devices indicate that approximately 15 percent of continuous bleed pneumatics exceeds manufactures design emission values by 1MMcf per year per controller. The key to a cost effective program is to develop an effective method for identifying the devices that need to be repaired or be replaced with new non-bleed or low-bleed equipment. Developing life cycle costs for different approaches for reducing emissions from pneumatics will be important in gaining gas industry acceptance.

Chemical injection and dehydrator pumps can also be replaced with air driven pumps or electric motors and emissions from blowdowns and storage tanks can be captured and re-injected into the pipeline by using a compressor. Acceptance of these approaches will be highly dependent on the results from this program to demonstrate that they are cost effective.

GRI will work with member companies, other gas industry organizations (e.g., INGAA, AGA, NGSA, NGPA and API), and existing government programs in developing the most cost effective implementation programs. GRI and a number of companies are participating in the Gas Star program. This program is an excellent source of information on reducing vented emissions and the cost of implementing these techniques. GRI would also plan to work closely with various Environmental Test Verification (ETV) Centers in developing the most cost effective implementation strategies.

The development of control strategies are needed to mitigate methane venting when transported, stored, filled, and used in NGVs. A systems "cradle to grave" study is needed to ascertain levels of potential methane venting and to document mitigation strategies.

Development Status: GRI has recently completed a comprehensive study cofunded with EPA to quantify methane emissions from the natural gas industry. GRI is currently cofunding a study with the industry and EPA to examine cost effective LDAR programs for natural gas transmission compressor stations and is also performing a similar study for the Russian natural gas system, sponsored by the U.S./Gazprom Work Group. GRI has developed the Hi-Flow™ Sampler for measuring leaks that is essential for establishing the costs and benefits of LDAR programs, repair techniques and capture and re-injection approaches.

While NGVs in the U.S. are approaching 50,000 in number, levels of methane emissions vary by vehicle type and filling and storage system.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
1000	1000	1000	1000

GRI cofunding of \$750,000 per year is anticipated.

IV. B. Methane Leakage Reduction

Application: Technologies will be developed for reducing leakage from natural gas production, processing, transportation, storage, and distribution.

Benefits: Based on a comprehensive study by GRI and EPA, leakage is responsible for over 60 percent of the 314 billion cubic feet (Bcf) of methane emitted by the gas industry. This is equivalent to approximately 80 million tons of CO₂ and the lost gas is worth over \$500 million per year at current prices. It is currently estimated that leakage could be reduced by 80 to 90 Bcf per year at compressor stations, alone, by instituting leak detection and repair programs and the industry could increase earnings by approximately \$80 million per year.

Program Description: The goal of the program is to implement methods and technologies for reducing leakage from the natural gas industry. This will be accomplished by completing three major tasks, (1) identify sources of emissions and methods for reducing leakage from the gas industry, (2) demonstrate leak reduction methods and collect data needed to perform a life cycle cost/benefit analysis, including capital, operating and maintenance costs, as well as data on effectiveness and durability, (3) develop strategies for implementing leak reduction technology. Developing life cycle costs will be important in gaining gas industry acceptance of any voluntary leak reduction program.

Leakage can be reduced by either detecting and repairing leaks or capturing the leak and re-injecting the gas into the system. Systems have been proposed for capturing and re-injecting leaks from the blowdown systems at compressor stations and from compressor seals. Implementing these types of systems could potentially reduce emissions from compressor stations by over 100 Bcf per year. The key to implementing a cost-effective leak detection and repair (LDAR) program is to be able to accurately measure the leakage once the leak has been detected. A cost-effective decision on whether the component should be repaired can only be made based on an estimate of the repair cost and a measurement of the amount of gas lost per year. GRI has recently developed a instrument to measure leakage and this instrument can be used to establish the cost effectiveness of LDAR programs and methods for repairing leaks from valves and other leaking components, as well as establishing the cost effectiveness of capturing techniques. GRI has also developed a new, optical methane detector that is being used on vehicular platforms. This concept could be further developed as a hand-held device, providing a more flexible, accurate instrument than is currently available.

GRI will work with member companies, other gas industry organizations (e.g., INGAA, AGA, NGSA, NGPA and API), government agencies and existing programs in developing implementation programs. GRI and a number companies are participating in the Gas Star program. This program is an excellent source of information on where leaks occur and on methods for repair and cost information. GRI would also plan to work closely with various Environmental Test Verification (ETV) Centers in developing implementation strategies.

Development Status: GRI is currently cofunding a study with the industry and EPA to examine cost effective LDAR programs for natural gas transmission compressor stations and is also performing a similar study for the Russian natural gas system, sponsored by the U.S./Gazprom Work Group. GRI has developed the Hi-Flow™ Sampler for measuring leaks that is essential for establishing the costs and benefits of LDAR programs, repair techniques and capture and re-injection approaches. GRI will also conclude the development of a vehicle-mounted optical methane detector system in early 1998. Further R&D is needed to reduce the size of the concept, to make the system easily usable by one person during a walking survey, and to reduce component costs.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
1500	1500	1500	1500

GRI and gas industry cofunding of \$500,000 per year is anticipated.

IV. C. Systems Optimization

Application: Studies will be conducted to optimize the U.S. natural gas system, electric and natural gas utility systems and industrial/energy processes to minimize greenhouse gas emissions while reducing operating costs.

Benefits: By examining a entire energy delivery system or industrial process, rather than focusing on specific functions, emissions can be reduced while decreasing operating cost. Studies will be conducted to determine methods for expanding the natural gas system while minimizing greenhouse gas emissions and operating costs. In addition a study will be conducted to optimize the energy delivered to the customer, whether it is electricity or natural gas, while minimizing emissions and cost to the customer. Finally, systems will be developed for producing energy and products while producing "zero emissions".

Program Description: Three studies will be conducted under this program based on the premise that both emissions and cost can be reduced by analyzing and optimizing the performance of the entire system. This is possible because many systems evolved and were not developed using an optimum approach. Also, since many systems were developed without consideration of costs for externalities associated with the current regulatory environment, such energy systems and industrial processes are considerably different than they would be if such costs are considered in an optimal system.

Expansion of the Natural Gas System: Current operation and maintenance (O&M) practices will be examined to determine if changes in O&M can result in cost effective increases in operating efficiency concurrent with emission reductions. This will not only include combustion equipment but also the effect of pigging on drag loss in the pipeline system. Monitoring or control system technologies associated with identifying and maintaining optimal O&M will be developed. In addition new technologies will be identified to efficiently expand the natural gas system, with technology feasibility and applicability to the current system identified. Approximately 5 to 6 percent of the natural gas produced is used by the industry for processing, storage, and transmission. Natural gas compressor stations use over 500 Bcf per year to transport natural gas from the wellhead to city gate stations. Some of the older reciprocating engines are also sources of methane emissions past the cylinders. Increased efficiency compressor station engines, if the efficiency of the equipment could be improved by 5 percent, could reduce CO₂ emissions by 70 million tons per year and save the industry approximately \$2.5 billion per year.

Optimizing Energy Delivery to the Customer: A study will be conducted at approximately six different regions of the country to determine the decrease in emissions and operating costs that could result if the electric and gas utilities in the region were operated as a single energy system to provide optimum energy services to the customer. Utility systems can reduce the cost of energy to customers as well as reduce emissions of greenhouse gas emissions by providing information and incentives to customers to install end use equipment that operates more efficiently with lower emissions while both the electric and gas utility can reduce their peak load. Additionally, enhanced equipment and system efficiency can reduce the need to expand the systems.

Design for Minimum CO₂ and Wastes (Zero Emission Systems): If a mandatory approach is implemented for controlling greenhouse gas emissions, the cost of externalities to the U.S. business community will be captured through either emission fees, emission credits, and/or controls. This new environment will offer many innovative industrial processes and energy generating systems that were economically infeasible the ability to compete with some existing systems with high external costs, such as the coal-fired electric utility boiler that has to control its SO₂, NO_x, PM and will now have to capture and sequester its CO₂ emissions. New approaches

toward designing and siting facilities will offer competitive advantages and increase the likelihood of an economically viable system. For example, with increased expense to capture and dispose of waste streams, system designs that not only minimizes waste but that produces waste that can be used as input to other processes (i.e., convert wastes to product) will have mitigated externality costs and attained an economic advantage. The practicality of co-locating industrial processes that offer complementary waste-to-product opportunities will be investigated. Co-location is a key component of success since converting waste to a product normally results in a low value product and transportation costs are a major problem unless the facility is located near the customer for the lower value secondary products. Systems that approach Zero Emissions by converting wastes to products, reducing transportation costs through siting, and mitigate the costs associated the practice of capturing and treating wastes will have an economic advantage. As part of this zero emissions philosophy, investigation of pipeline and distribution main abandonment should be conducted. For instance, in some very limited cases, PCBs have entered the pipeline system. Source and sink studies need to be conducted and decontamination strategies, if needed, should be developed.

The objective of this multi-phase study is to develop systems that have "Zero Emissions." This is intended to be a multi-phase study. Phase I will be to solicit ideas through RFPs and workshops. Phase II will identify the most promising ideas based on an initial investigation of technical issues and a preliminary cost analysis. Phase III will fund research on key technical issues and refine cost estimates. Phase IV will select one or more projects for a pilot plant demonstration, design the pilot plant facility, and find commercialization partners.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	500	500	500

GRI cofunding of \$500,000 per year can be anticipated.

IV. D. Natural Gas Technology Greenhouse Gas Emissions Management

Application: Identify approaches and technologies for concurrently minimizing emissions of greenhouse gases and of fine particulate matter (PM_{2.5}) precursors.

Benefits of the Technology: Parallel goals exist for air quality management and global climate change mitigation. This research will provide guidance for selection of the best and most cost-effective technologies and strategies for meeting both goals concurrently. Improvements in PM_{2.5} measurement technology will be recommended to eliminate sampling biases which could influence emission reduction decisions.

Technology Description: New National Ambient Air Quality Standards for PM_{2.5} and ozone will require reductions of gaseous precursor emissions. Southern California Gas Company, which serves 4.8 million customers, is funding work with ENSR on a Phase I effort to assess contributions to PM_{2.5} due to natural gas combustion, based on linear rollback modeling and quantification of the conversion of gaseous emittants to particulate species. Strategies for air quality management do not currently encompass the mitigation of greenhouse gas emissions, and thus could be at cross-purposes with the need for global climate management. The Phase II effort proposed here would focus on the coordination of the greenhouse gas and PM_{2.5} goals. An assessment of the environmental benefits and costs of strategies and technologies that are available or under development is proposed. Special attention will be paid to improvements needed in particulate modeling technology and in PM_{2.5} measurement technology, including denuder technology to improve the accuracy of nitrate measurements.

An assessment would take place during the first year for Southern California, where an aggressive air quality management program is in place, a variety of innovative strategies and technologies are already being applied, and an extensive air quality data base exists. Analyses during the second year would address other areas of the country where strong measures to manage air quality are expected to be needed, and analyses during the third year would address the nation as a whole. The products would be a workbook for assessing the greenhouse gas and PM_{2.5} ramifications of emission management decisions, plus a description of measurement technology improvements needed to eliminate sampling biases.

Development Status: Much of the data needed for this technology assessment is available for current strategies and technologies, but research is required to develop comparable information for evolving technologies and to focus concurrently on CO₂ reduction and air quality management goals.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	1000	1000	---

GRI and gas industry cofunding of \$500,000 per year is anticipated.

IV. E. NO_x Abatement and Efficiency Improvements for Engines and Burners

Application: Applied research for natural-gas engines and burners.

Benefits of the Technology: Natural gas use in the industrial and electric power generation sectors alone accounts for 12 quads of annual energy use. Additionally, residential use of gas, particularly home furnaces, accounts for nearly 5 quads of natural gas. Research to reduce NO_x emissions and concurrently to increase or maintain efficiency in these sectors, as well as in the emerging transportation applications for natural gas, can have tremendous implications for efforts to reduce greenhouse gases. While NO_x is not a primary greenhouse gas, it has been identified as a ground-level ozone (a greenhouse gas) precursor.

Technology Description: Although natural gas engine-driven systems are highly efficient and produce relatively low emissions of CO₂, focusing on reducing emissions of NO_x alone can actually result in reducing system efficiency. For example, the singular drive to reduce NO_x in gas turbines can be achieved by lowering turbine inlet temperature. However, this will lead to reductions in gas turbine efficiency. Concurrent consideration of ambient air quality and efficiency is needed to ensure that both air quality improvement and greenhouse gas reduction goals are met. Natural gas engines and industrial boilers and burners can benefit from NO_x abatement and efficiency improvement applied research to reduce these specific emissions while maintaining efficiency at levels which are consistent with or exceed the levels already attained from relatively clean natural gas devices.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
6000,	6000	4500	---

Gas industry cofunding of \$400,000 per year is anticipated.

Program Element V. International Technology Transfer

V. A. International Technology Transfer

Application: The technology strategies pursued in the U.S. for enhanced natural gas use, energy efficiency, and expanded supply will be applicable throughout the world. In addition, spin-offs from some of the technology developments could allow more rapid development of natural gas infrastructure in developing countries. For example, development of composite pipe for increasing pressure and deliverability of the U.S. pipeline system could be applied to composite tube barges for low-cost transport of natural gas from remote sources to new natural gas combined cycle power plants in advance of high pressure transmission pipe installation anywhere in the world.

Benefits: Worldwide application of natural gas technologies that displace higher-carbon fossil fuels will contribute to the goal of reducing global greenhouse gases. Should international trading of carbon credits be adopted, the U.S. could take significant advantage of providing technology solutions throughout the Americas and overseas.

Program Description: Key technologies to expand global gas availability include: recovery of gas from coal seams, and deep water drilling and processing.

Examples of technologies developed through this U.S. national program that can expand the gas transmission infrastructure in other countries include: a) high pressure composite piping; b) pipeline automation, monitoring, and inspection; c) low emission, high efficiency modular compressor stations; and d) methane emissions detection and control.

Technologies that encourage increased natural gas use in lieu of other fossil fuel use include: a) gas cooling and heat pump systems; b) small and mid-scale gas turbines for power generation; preferably combined cycles; c) residential and commercial cogeneration systems; d) natural gas vehicles and hybrid vehicles; and e) natural gas high-efficiency industrial burners and boiler equipment.

Development Status: Several technologies are already well developed and are in application in the U.S. that could be transferred. Examples include coal seam gas recovery, pipeline automation, and high-efficiency industrial equipment. Other technologies in various stages of development will result from the proposed overall natural gas program, providing a stream of opportunities for international technology transfer.

The infrastructure for technology transfer is largely in place through U.S. participation in the International Energy Agency (IEA) and the International Gas Union (IGU). In addition, GRI manages the International Center for Gas Technology Information (ICGTI) through its joint venture, Gas Technology Information (GTI), and operates an International Associate Member program with 28 members representing gas companies all over the world.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
800	800	800	800

GRI and GTI cofunding of \$500,000 per year is anticipated.

V. B. Natural Gas Industry Challenge Program

Application: Register all actions taken by the natural gas industry to reduce its emissions of greenhouse gases or to reduce such emissions by others.

Benefits of the Program: Promotes the reduction of greenhouse gases in natural gas production, transmission, distribution, and end-use systems on a voluntary basis.

Program Description: Parallel but distinct program to the current efforts under Section 1605(b) of the Energy Policy Act of 1992. Distinct program would separately recognize the accomplishments of the natural gas industry's efforts to reduce greenhouse gas emissions. Specific actions by gas industry might include direct efforts to measure and reduce leaks in gas distribution systems and other internal utility operation efficiencies, and end-use measures such as the conversion of vehicle fleets to cleaner-burning natural gas, substitutions of gas cooling load for electric peak load, gas end-use efficiency enhancements to reduce emissions, and assistance to and investments in non-domestic utility emission reductions.

Attention must be given initially to measurement protocols and to educational materials and conferences which are specific to the needs of the natural gas industry in the reduction of greenhouse gases. The American Gas Association is prepared to assist the Department of Energy in the formulation of an effective voluntary emission reduction program tailored to the needs of the natural gas industry.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
1500	1000	1000	1000

V. C. Residential Gas Cooling Joint Marketing Program

Application: Technology is suitable to retrofit a majority of the 76 million residential buildings existing in the U.S. and for most new home construction.

Benefits of Program:

- Potential to reduce CFC (a primary greenhouse gas) and CO₂ emissions in the space conditioning market by more than 50 percent.
- Dramatically improves energy efficiency in the most energy-consuming end use of the residential sector, space conditioning. Residential space conditioning requires approximately 8 quads of energy each year and is growing at a two percent rate.
- Substitutes for relatively "dirty" summer peak electric generating facilities.

Program Description: Federal government should conduct a cost-shared joint marketing program with natural gas distribution companies, manufacturers, and service industry representatives to address barriers to market entry and to accelerate market penetration by natural gas heat pump technologies. Specific activities of the joint program should include: additional research and development to increase the efficiency and reduce the capital cost of gas cooling equipment; dealer and distributor training/certification to reduce maintenance concerns; and outreach to decision-makers such as architects, builders and military housing authorities who select or maintain residential space conditioning equipment.

Development Status: Advanced gas cooling/heating options, including: the Triathlon, the GAX, and solid adsorbent technologies all have higher capital costs than conventional residential air conditioners and space heating systems. Heating efficiencies for these advanced technologies are 120-150%; cooling efficiencies are 80-120%. Despite significantly lower operating and lifecycle costs for gas cooling technologies, the higher first-cost continues to be a barrier to market entry for this first of a kind technology.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
5,000	5,000	4,000	---

Gas industry cofunding of \$2,000,000 per year is anticipated. Additional cofunding from manufacturers is possible.

V. D. School & Institutional Building Desiccant Initiative

Application: Deployment of desiccant-based space conditioning technology in schools, hospitals and other public buildings.

Benefits of Program: Retrofit of desiccant technology into existing cooling systems in public buildings can reduce energy use and associated emissions by one third. Replacing conventional space conditioning systems with all new gas-fired desiccant-based systems can reduce emissions by well over 50 percent, and eliminate CFC usage in those applications.

Program Description: The increased efficiency and net reduction in CO₂ and CFCs by desiccant systems need to be demonstrated. Conduct a federally-sponsored campaign and field tests to promote the use of desiccant-based dehumidification technology in public buildings. Indoor air quality in many public buildings is a problem that can be ameliorated with the use of desiccant technology. The GAO has concluded recently that fifteen percent of U.S. schools, for example, suffer from poor indoor air quality. Due to high humidity levels in many regions of the country, ventilation with outside air often exacerbates the air quality problem because conventional space conditioning equipment is inadequate to remove significant moisture and can actually promote further mold, mildew and other related pollutants in "sick buildings."

The DOE, the Department of Education, the Veterans Administration, the Department of Defense and other federal agencies should participate with industry in a program to reach out to the designers and decision-makers for space conditioning equipment in schools, hospitals, and other public building. Specifically, this program should : identify parties with responsibility for equipment choices in public buildings; prepare outreach plans tailored to specific parties as identified; demonstrate desiccant technology operations and benefits through field tests in conspicuous public buildings; and, work with desiccant manufacturers, the American Gas Cooling Center and others to sponsor educational materials and meetings to promote the indoor air quality, energy and global environmental benefits of desiccant technologies.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
2,000	2,000	2,000	—

Gas industry cofunding of \$1,000,000 per year is anticipated.

V. E. Systems Design Competition for Gas Cooling

Application: Technologies are suitable for both new and retrofit designs of residential and commercial buildings.

Benefits of Program:

- Potential to reduce greenhouse gas emissions (e.g., CFCs) in building stock by integrating subsystems within a building that relate to the heating, ventilation, and air conditioning equipment.
- Improves energy efficiency in buildings because it allows utilization of waste heat and complimentary systems. Has the ability to reduce energy use by 50% in many U.S. buildings.
- Allows the off-loading of peak electric demand during summer cooling months and the accompanying reduced consumer power costs.

Technology Description: Gas-fired and electric heating, cooling, and ventilation technologies have traditionally been treated as separate technologies and have been evaluated for their efficiency, economics and global warming technologies independently. Putting technologies together as a system can save significant energy and costs. For example, pairing a desiccant with a combination gas and electric heating and cooling system can reduce overall energy use by as much as 50% and thereby reduce costs and greenhouse gases. A design competition is the ideal method by which to get architects, engineers, and students thinking in terms of system design that maximizes potential benefits of reducing overall energy load in buildings. It is suggested that the competition would be open to both retrofit and new construction projects.

Federal Funding Requirements (\$1000):

<u>FY 1999</u>	<u>FY 2000</u>	<u>FY 2001</u>	<u>FY 2002</u>
500	500	500	---